S. Hrg. 101-538

COMPETITIVE WHOLESALE ELECTRIC GENERATION ACT OF 1989

HEARINGS

BEFORE THE

COMMITTEE ON ENERGY AND NATURAL RESOURCES UNITED STATES SENATE

ONE HUNDRED FIRST CONGRESS

FIRST SESSION

ON

AMENDMENT NO. 267 TO S. 406

NOVEMBER 9 AND 16, 1989

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Committee on Energy and Natural Resources

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COMPETITIVE WHOLESALE ELECTRIC GENERATION ACT OF 1989

THURSDAY, NOVEMBER 9, 1989

U.S. Senate,
Committee on Energy and Natural Resources,
Washington, DC.

The committee met, pursuant to notice, at 9:34 a.m. in room SD-366, Dirksen Senate Office Building, Hon. J. Bennett Johnston, chairman, presiding.

OPENING STATEMENT OF HON. J. BENNETT JOHNSTON, U.S. SENATOR FROM LOUISIANA

The Chairman. The hearing will come to order.

This morning the Committee on Energy and Natural Resources begins consideration of one of the most important issues facing the electric utility industry today. We are here to ask the question: to what extent should independent power production and competition in wholesale generation be options in ensuring our future electric supply?

At the outset, we should realize that wholesale competition and independent power in the form of QFs under PURPA are already a reality. There are approximately 25,000 megawatts of QFs on line with more on the way.

In addition, nearly half of the states have adopted or are in the process of adopting competitive bidding for the acquisition of new capacity by their native utilities.

We are told, however, that the progress of competition is becoming increasingly restricted. It seems that the PURPA box is a little too small and too rigid. Developers, both utility and nonutility, are finding that the steam requirement for cogeneration and the size and fuel limitations for small power production preclude many otherwise beneficial opportunities in power generation.

In addition, critics of PURPA point out that existing limitations on utility ownership and mandatory purchase requirements do not make any particular sense in the context of a competitive wholesale market.

Recently, companies have begun moving beyond the PURPA model to develop independent power producers or IPPs. IPPs are wholesale power plants that sell power at market prices and are not subject to the size, ownership or technological restrictions of PURPA. The movement toward IPPs, however, is presently impeded by the provisions of the Public Utility Holding Company Act of 1935.

For anachronistic reasons, the Holding Company Act substantially restricts the ability of companies, whether utility or nonutility, to use holding company structures for the generation of electricity. Developers generally must use holding companies to develop IPPs for financial and regulatory reasons. Therefore, without changes to the Holding Company Act, significant growth of IPPs and wholesale power generation cannot take place.

Thus, the specific issue before us is, should the impediments in the Holding Company Act be removed? Legislation I have introduced, the Competitive Wholesale Electric Generation Act, would do just that; but by introducing the legislation my intention is to begin a constructive debate on the mechanisms of future electric supply.

My own mind is not made up and does not have a bias in either direction on the question. I anticipate that the committee's hearings on Amendment 267, as this legislation is called, will be extremely useful in sorting out the complex arguments for and against this proposal.

Those who argue against enhancement of competition and wholesale generation express concern that such action will cause loss of economies of coordination, lack of reliability, unwise fuel choices, overreliance on contractual obligations as a means of ensuring power supply, and overemphasis on price versus nonprice factors in purchasing power competitively.

In general, they assert that the natural monopoly characteristics of generation remain intact and that vertically integrated utilities are most likely to be able to provide adequate reliable power at least cost.

Those who support Holding Company Act changes cite the positive experience for the competition under PURPA; the present existence of willing buyers and sellers for IPP power who are stymied by the Holding Company Act; the preference of economic theory for workable competition overregulation; the growing concern by some analysts that utilities by themselves will have difficulty in meeting imminent needs for new generation.

In general, advocates of change point out that if the Holding Company Act legislation merely creates the option but not the requirement for independent power production, one must assume serious and prolonged errors in judgment by both purchasing utilities and State regulatory commissions in order to argue that the Nation's electric supply would be harmed by enactment of legislation.

In other words, if in a given instance IPP power is unacceptable, it simply need not be purchased.

In judging between these two positions, the committee must recognize that an ample, economical and dependable supply of electricity is fundamental to every aspect of the Nation's well being. Major decisions on electric regulation should not be made lightly. On the other hand, few policy changes are ever made without some uncertainty and ultimately some negative consequences. The task will be to balance all the appropriate considerations.

I might say before I recognize my distinguished colleague, Senator McClure, that I have been lobbied somewhat on this issue, and I want to tell my friends on both sides of the issue that this really is not the time for lobbying from a political standpoint. We are politicians, and we heed what our friends say in that respect. I do not mean to say that we are going to resign from the political arena.

I do mean that this is a very, very serious question supported and opposed by very serious and important people in the electric industry and all across America. It is a question that will be explored by someone at some time, and I think this committee is the most appropriate one to explore it.

So what we are about on our hearing today, on our hearing which I believe is next week, on our hearings in early next year, is to determine what the best thing to do is with this issue. The time will come when we will either propose or not propose, and you can corral votes. For now, we want to marshal the arguments.

As far as I am concerned, I am here to be persuaded, to find out, to learn what the truth of the issue is on this most important issue.

Senator McClure.

[The text of amendment No. 267 to S. 406 follows:]

IIIA

AMENDMENT NO. **267** Calendar No.

Purpose: To remove obstacles to competition in wholesale electric generation markets and for other purposes

IN THE SENATE OF THE UNITED STATES—101st Cong., 1st Sess.

S. 406

To authorize competitive oil and gas leasing and development on the Coastal Plain of the Arctic National Wildlife Refuge in a manner consistent with protection of the environment, and for other purposes.

July 17 (legislative day, January 3), 1989

Referred to the Committee on Energy and Natural Resources and ordered to be printed

AMENDMENT intended to be proposed by Mr. JOHNSTON

Viz: Strike all after the enacting clause and insert the following:

That this Act may be referred to as the "Competitive Wholesale Electric Generation Act of 1989".

SEC. 2. EXEMPT WHOLESALE GENERATORS.

(a)(1) "Exempt wholesale generator" shall mean any person who is engaged directly, or indirectly, through one or more affiliates of such person as defined under section 2(a)(11)(B) of the Act, exclusively in the business of owning or operating all or part of one or more eligible facilities and selling electric energy at wholesale: *Provided,* That the term "exempt wholesale generator" shall exclude an affiliate of a registered holding company, which affiliate was in existence as of the date of enactment hereof, unless the Commission has consented.

(2) "Eligible facility" shall mean a facility, wheresoever located, used for the generation of electric energy exclusively for sale at wholesale (including interconnecting transmission facilities necessary to effect such sale at wholesale), but shall exclude any facility for which consent is required under paragraph (3) and has not been obtained. For purposes of this subsection, the term "facility" shall include a portion of a facility.

(3) As of the date of enactment hereof, if a rate or charge for, or in connection with, the construction of a facility, or for electric energy produced by a facility (other than any portion of a rate or charge which represents recovery of the cost of a wholesale rate or charge) was in effect under the laws of any State, consent with respect to such facility shall be required from any State commission having jurisdiction over such rate or charge.

(b) An exempt wholesale generator shall not be considered an "electric utility company" under section 2(a)(3) of the Act and, whether or not a subsidiary company, an affiliate, or an associate company of a holding company, shall be exempt from all provisions of the Act.

(c) Notwithstanding any provision of the Act, a holding company that is exempt under section 3 of the Act shall be permitted without condition or limitation under such Act to acquire and maintain an interest in the business of one or more exempt wholesale generators.

(d) Notwithstanding any provision of the Act and the Commission's jurisdiction as provided under subsection (e), a registered holding company shall be permitted without the need to apply for, or receive approval from the Commission, and otherwise without condition under the Act, to acquire and hold the securities, or interest in the business, of one or more exempt wholesale generators.

(e) The issuance of securities by a registered holding company for purposes of financing the acquisition of an exempt wholesale generator, the guarantee of securities of an exempt wholesale generator by a registered holding company, the entering into service, sales or construction contracts, and the creation or maintenance of any other relationship in addition to that described in subsection (d) between an exempt wholesale generator and a registered holding company, its affiliates and associate companies, shall remain subject to the jurisdiction of the Commission under the Act: *Provided*, That—

(1) section 11 of the Act shall not prohibit the ownership of an interest in the business of one or more exempt wholesale generators by a registered holding company (regardless of where facilities owned or oper-

ated by such exempt wholesale generators are located), and such ownership by a registered holding company shall be deemed consistent with the operation of an integrated public utility system; and

(2) the ownership of an interest in the business of one or more exempt wholesale generators by a registered holding company (regardless of where facilities owned or operated by such exempt wholesale generators are located) shall be considered as reasonably incidental, or economically necessary or appropriate to the operations of an integrated public utility system.

(f) For purposes of this section, all references to "the Act" shall mean the Public Utility Holding Company Act of 1935, as amended. All of the terms used in this section and defined in the Act shall have the same meaning as defined therein.

SEC. 3. OWNERSHIP OF EXEMPT WHOLESALE GENERATORS AND QUALIFYING FACILITIES

The ownership by a person of one or more exempt wholesale generators shall not result in such person being considered as being primarily engaged in the generation or sale of electric power within the meaning of sections 3(17)(C)(ii) and 3(18)(B)(ii) of the Federal Power Act, as amended.

SEC. 4. PRESERVATION OF STATE AUTHORITY.

Nothing in this Act shall preempt or otherwise restrict such power as a State regulatory authority may have, in accordance with State and Federal law and in the absence of the enactment of this Act, to judge the prudence of a purchase of electric energy at wholesale, deny the inclusion of the cost of such a purchase in rates subject to such authority's jurisdiction, or otherwise exercise its functions.

STATEMENT OF HON. JAMES A. McCLURE, U.S. SENATOR FROM IDAHO

Senator **McClure**. Thank you very much, Mr. Chairman. I appreciate the hearings because I, like you, need to hear the best arguments people on opposite sides of the issue can make.

This pending matter has been described by some as minimalist, changing the Holding Company Act only enough to allow independent power producers to be built without running afoul of the Act's restrictions.

Although it is true that the pending legislation makes only limited changes in the Holding Company Act, it appears that these changes would have far-reaching impacts. Coming from a mountain state and getting ready for the winter season, I am reminded that an avalanche is sometimes started by a single snowflake. At this time I neither favor nor oppose this legislation. I simply do not know enough about this extremely complex matter to have an adequate basis for reaching a judgment.

As a necessary first step in making my assessment, I need to know what problems this legislation proposes to solve, how it would solve them, and what direct and indirect consequences it would have. Only then can I reach a reasoned judgment.

Mr. Chairman, if I may digress briefly before hearing from the witnesses, I think it may be important to remind the proponents of this legislation that the legislative process does not necessarily result in creating the product that people want or expect. As a prime example, I point to the Electric Consumer's Protection Act of 1986, the so-called Hydroelectric Relicensing Bill.

There, we started out with a very simple concept which was easily stated in a few words of legislative language, but by the time the House-Senate Conference finished, it was 18 single-spaced pages long and contained numerous extraneous provisions on matters such as antitrust, wheeling, fish and wildlife protection, PURPA, and a $10,000 per day fine for those who violated the Act. I hope we do not have the same experience with this bill.

I would also like to take this opportunity to express a concern of mine; that is, that utilities are likely to delay construction of needed new power plants until we act on this legislation. At this time, there is simply no way to predict whether or not Congress will ever complete action on this bill. Legislation on this subject has been before the Congress for a number of years without a bill being signed into law. I hope our attempt to look into this important matter does not, in fact, result in that type of delay which we would all certainly want to avoid.

I want to get back to the basic questions. What are we trying to fix? What are the problems that we perceive which need to be fixed? I cheerfully for myself would have some years ago repealed PURPA. I think it has acted in ways that Congress never intended and certainly did not expect. Now we have a constituency built around that that makes it almost impossible to change it.

I want to look at this legislation very carefully because I do not know that I am prepared at this time to say that I understand what problems this is designed to fix and if there are other ways to fix the problems we perceive. So I am very openminded at this point. I look forward to the testimony.

I realize that there is a great deal of discussion and disagreement within the industry as to whether this is the way to go. I want the people who say it is the way to go to tell me why. I want those people who say, hey, this is a bad idea whose time has not come to tell me why that is true. Maybe out of that we can make a reasoned judgment about the problems and how we ought to try to fix them and avoid some pitfalls that might otherwise occur.

Thank you very much, Mr. Chairman.

The CHAIRMAN. Thank you, Senator McClure.

Senator Ford.

Senator FORD. Mr. Chairman, I have no statement, but listening to you and Senator McClure, it is going to be an interesting two or three days of hearings. You do not know what is broken, and then these people are going to tell you how to fix it. So if we do not know what is broken and we do not know how to fix it, I wonder why we are in this arena. [Laughter.]

Nevertheless, I look forward to hearing the pros and cons and looking to your leadership to help me out.

The CHAIRMAN. Thank you, Senator Ford.

Senator Burns.

Senator BURNS. I have almost the same comment. I will just be a willing listener. Thank you very much.

The CHAIRMAN. Senator Wirth.

STATEMENT OF HON. TIMOTHY E. WIRTH, U.S. SENATOR FROM COLORADO

Senator WIRTH. Mr. Chairman, I am delighted to be here. We have a number of very easy issues in front of us, I know, in this piece of legislation, and I look forward to hearing from all of you. I think there are some great opportunities in this, but I think we want to be careful in sorting them out. I am glad you are having this hearing.

Thank you, Mr. Chairman.

The CHAIRMAN. Thank you very much.

We are very pleased to have an outstanding two panels today. One group favors the Holding Company Act changes. The other group opposes these changes. I thought we would proceed a little bit differently from our usual way today; that is, to recognize one side for whatever reasonable period you think is proper, somewhere around 20 or 25 minutes, letting you divide up your time as you wish, and then the other side will come in with a negative view for an equal amount of time. From there, we will just have a free-for-all with the committee jumping in with questions. [Laughter.]

We will see where we go from there.

Those favoring the Act are: William T. McCormick, Chairman and CEO of CMS Energy Corporation of Jackson, Michigan; Mason Willrich, President and CEO of PG&E of San Francisco; and Paul J. Elston, CEO of Long Lake Energy Corporation of New York.

Those opposing changes are: Richard Brooks, President and CEO of Central and South West Services from Dallas; Drue Jennings, President and CEO of Kansas City Power and Light; and Joseph F. Paquette, Chairman, President and CEO of Philadelphia Electric.

Gentlemen, with that I look forward to an interesting morning. Mr. McCormick, why not lead off.

STATEMENT OF WILLIAM T. McCORMICK, JR., CHAIRMAN AND CHIEF EXECUTIVE OFFICER, CMS ENERGY CORP./CONSUMERS POWER CO., JACKSON, MI

Mr. McCormick. Mr. Chairman, glad to be here. Consumers Power Company, which is our major subsidiary, serves 6 million of the 9 million in the State of Michigan for electric, gas or both.

Let me say at the outset that I am one who strongly supports the changes in the Holding Company Act. I am not here representing anybody but my own company, but I should say that the 17 members of the utility working group who will be testifying later share many of the views that I will be discussing this morning.

I would like to touch on really four issues: the need for amending PUHCA, which gets to Senator McClure's question of why we need it, what is broken; the second, the efficacy of an industry structure which includes wholesale power; third, the essential elements of PUHCA reform as we see it; and fourth, issues that we believe should not be included in the legislation.

I think on the question, first of all, Senator McClure, of why we need this, I think the major reason is that we have a serious electricity shortage coming in this country. Economic growth is producing 2 or 3 percent a year. Frankly, the number of new plants and the construction plans of the electric utility industry are very modest indeed. We are already seeing shortages in New England and the Middle Atlantic States. In our region of the country, the midwest, we are looking at reserve margins declining very rapidly.

If you look at those construction plans, you can see that plants just are not being built. In my region of the midwest we have 96,000 megawatts of installed capacity, and there are only 4,000 under construction. That is barely 1.5 years of growth. Knowing the lead times of power plants, 7 to 10 years, we are staring a serious problem in the face.

I think the question that we need to ask is why is this generating capacity not being built. I think the answer is that utilities have generally become risk adverse in building new capacity. I think their boldness in building capacity in the 1970s to meet a perceived demand has been met with large disallowances by public service commissions that have made them very cautious in building new capacity.

In fact, Morgan Stanley recently reported that of the roughly $130 billion of investment made by utilities over the last five years, 10 percent of it, $13 billion, has been disallowed by State regulators. Many of these are also espousing new ways of doing business: integrated resource planning, least cost power planning, competitive bidding strategies. We have 14 already with competitive bidding strategies and another 12 that are looking at them very seriously.

That means that no longer are traditional rate base projects, the way we have been doing business, considered prudent because they are going to want to see, well, your rate base project may have been good in the past, but we want you to competitively bid. We want to see if there are people out there who can produce power as cheaply as you can. That is forcing many of us in the utility industry into a posture where we see the need to have new alternatives.

In order to provide both utilities as well as consumers with new alternatives, we believe it is important that the independent power option be opened up.

Now we are not forcing any utility, not any utility sitting at this table or any utility in the country, necessarily to use this option. If they do not want to bid for power, if they want to continue to build rate base power, God love them. Let them do it. But for the rest of us, we want the option to go out and get power under different ways of procuring it.

Now moving on, I want to discuss a couple of the arguments that have been raised by utilities who oppose the independent power argument or oppose amending the Holding Company Act.

The first one they raise is that a fully integrated electric utility industry is essential to provide reliable service and ensure the obligation to serve. I believe that the electric utilities that support changes in the Holding Company Act are just as concerned about reliability as those who oppose it.

I think it is also important to note that the electric utility industry is probably the last regulated industry in this country that is completely vertically integrated. Now I am not saying there is anything wrong with that. I think it can work fine.

On the other hand, let us look at the gas industry. The gas industry has a distribution sector. It has a transmission sector. It has a producing sector. The gas industry is an important industry to the vitality of this country. The telephone industry essentially has a distribution sector, a long-range transmission and an equipment sector.

So here we have two other utilities that basically work pretty good. The gas industry has contracts between producers and pipelines and between pipelines and distributors. To make the argument that you cannot have electric generation, you cannot take one of those three segments, the producing sector, and have a competitive nonintegrated or disintegrated part of that industry that can have contractual relationships with the others, is simply absurd, because we have it in the gas industry and it is working fine. In fact, it is very competitive.

I think another point along those lines is most of the utilities, many of them and certainly most of the rural electrics, municipals and many small distribution companies, electric utilities in this country, are already simply distribution companies. They purchase their power already. There are many utilities in this country that do not produce any of their power.

So the idea of purchase contracts and reliability between producers of power and distributors of power is already going on, and I think to make the argument that that is going to unnecessarily reduce reliability is simply not true.

I think another argument that is used is that the service will diminish and the reliability of the plants will not be as good. I think, again, this argument is terribly, terribly weak. There is plenty of data to demonstrate the reliability of independent power generation and independently owned plants. We have many of them. My colleague from PG&E will describe some.

I think another important point is many of these plants are owned and operated by large multi-billion dollar corporations, Dow Chemical, Enron, Coastal, Combustion Engineering, Bechtel. So a lot of the argument used is that many of these independents are going to be weak, undercapitalized, fly-by-night companies that are not going to be able to provide a service. That simply is not true. There is going to be a range of players and a range of participants.

I think on this point it is going to be up to the utilities procuring the power to decide what kind of specifications they want to have. If they want to have certain specifications on financial integrity and viability, if they want to have certain specifications on the quality of the power, if it is dispatchible or nondispatchible, or any other specs, they can make those specs, put it out, and anyone who can meet those specs can pick the best one.

So we are not suggesting that utilities be required—and they certainly are not under the Chairman's proposal—to purchase power from anyone in particular or to purchase power from people who are not reliable enough to supply that power.

I think integrated utility ownership is one way of achieving reliability, and contracting is another. The real point, I think, is that we ought to have a choice.

I think traditionally utilities also criticize the bill that it would break the successful regulatory compact, and as I said before—and I am repeating myself but I think it is worth making the point again—nobody, no utility, is forced to use this option. It does provide an option for those of us who see that it can benefit the consumers.

I think another criticism is that the legislation would confiscate utility transmission lines by nonutility wholesale generators and displace existing utility customers. Again, I think this is a red herring.

Frankly, there is nothing in this bill that would force that. FERC has the requirement under the law to administrate wholesale power transmission. They have indicated already in their case not only with Portland but also in the case of Citizens Energy that they are going to be looking at transmission access and looking at the issues associated with that and that they are going to ensure that there will be no anticompetitive actions taken. So I am not particularly concerned about that.

I think the essential elements, the third part of my presentation, that we need to have are basically the ones that are in your bill: creation of a new class of wholesale generators that can compete, allowing both utility and nonutility affiliates and affiliates of holding companies to participate on a level playing field; ensuring that all owners would be exempt from the Holding Company Act with respect to their ownership; and ensuring that ownership or purchasing from an exempt generator is purely voluntary either to participate or not participate or to buy or not buy.

I think those issues which should not be included in the legislation are any restrictions on utility ownership as an independent power. I think there are two reasons for this. One is that many utilities——

The **Chairman**. Mr. McCormick, excuse me. I do not want to stop you in the middle of making a good point, but we would like to have each side at about, let us say, 25 minutes. So if you will govern your time accordingly.

Mr. **McCormick**. I will finish in two minutes if that is all right.

The **Chairman**. That is fine.

Mr. **McCormick**. The point I was making is that I think with respect to utilities participating, I think it is terribly important that they do that for two reasons. Number one is that many of them have the expertise to participate as nonutility generators, and I think the second point is that many State commissions are going to be forcing competitive bidding in the utility service area, and they will not have the alternative in many cases of billing rate base capacity.

They should be allowed, therefore, to participate in their own areas lest they be relegated to confiscation and liquidation.

As I mentioned before, I think the FERC has adequate authorities in the transmission area, and I think it would be a mistake for the Congress to attempt to include anything in this bill that would mandate transmission access or force the transmission issue. This is a very complex regulatory issue. Every company in the country has a different transmission system. The transmission system was not built like the interstate gas system. It was built up as a patchwork for reliability reasons, and there are many parts of it that really cannot stand additional flows which will require a case-by-case examination by appropriate regulatory authorities. I do not believe it is something that could be legislated.

In summary, Mr. Chairman, I strongly support the changes that you recommend in your bill. I believe it presents a new valuable option for the utility industry and its consumers, and I believe it does not force anybody to do anything they do not want.

Thank you very much.

[The prepared statement of Mr. McCormick follows:]

TESTIMONY OF
WILLIAM T. McCORMICK, JR.
CHAIRMAN & CHIEF EXECUTIVE OFFICER
CMS ENERGY CORPORATION/CONSUMERS POWER COMPANY
BEFORE THE
COMMITTEE ON ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE
NOVEMBER 9, 1989

Mr. Chairman and members of the Committee:

My name is William T. McCormick, Jr. I am Chairman and Chief Executive Officer of CMS Energy Corporation (CMS), an exempt holding company as defined by the Public Utility Holding Company Act of 1935 (PUHCA). CMS is a $3 billion (sales) diversified energy corporation involved in energy production, transmission and distribution. The largest subsidiary of CMS Energy is Consumers Power Company, a combination utility that provides electricity and natural gas service to about six million of the nine million residents of Michigan.

I am pleased to have been invited to appear before the Committee today to discuss S. 406, the "Competitive Wholesale Generation Act of 1989," which you introduced earlier this year. May I say at the outset that I strongly support S. 406 and wish to thank you for introducing it. My company is also a member of the Utility Working Group, a coalition of 17 utilities that support PUHCA reform such as contained in S. 406. As Senator Johnston correctly noted in his remarks September 12, 1989 before the Kidder, Peabody legislative forum in Washington:

> "For the last two years, there has been an intensive policy debate on the issue of competition in wholesale generation. The debate has involved regulators, utility

> executives, consumers advocates, aspiring independent power developers, economists, lawyers, and investment bankers. It has occurred before state utility commissions, before FERC, and in endless numbers of studies, conferences, seminars and symposia. It is time for the debate to be brought to Capitol Hill."

In my remarks, I will address four major subjects:

1. The need for amending PUHCA and the benefits to U.S. electricity consumers.

2. The efficacy of an industry structure which includes Wholesale Power Generators.

3. The essential elements of effective PUHCA reform.

4. Issues that should not be included in legislation amending PUHCA.

Need to Amend PUHCA

I believe that amending PUHCA is an essential action that Congress must take in order to ensure that adequate supplies of electricity are available in the mid to late 1990s.

Nationwide demand for electricity is growing at a rate that parallels the growth of the national economy, that is about 2% to 3% per year. Indeed, a 1988 study by the U.S. Department of Energy predicts that, even if electricity demand grows by only 2 percent annually, the country will need 100,000 megawatts of additional electricity generating capacity by the year 2000 -- just about 10 years from now. This 100,000 megawatt figure assumes that demand-side measures to conserve electricity consumption will be aggressively applied, and there is no certainty of this.

When one examines the construction plans of the nation's electric utilities, it is clearly apparent that the U.S. is rapidly headed for electricity shortages unless significant new generating capacity is committed in the very near future. Shortages have already occurred in New England, the mid-Atlantic states and other parts of the U.S. and the reserve margins in the Midwest are declining at uncomfortable rates.

For example, in my region of the country, the East Central Area Reliability Council (ECAR), only about 4,000 megawatts of new capacity is currently being constructed or about 4% of ECAR's total of 96,000 installed megawatts. This new capacity will provide less than two years' of the region's electricity growth at 2% per year.

One might ask why adequate generating capacity is not being constructed by some utilities? The answer is that many utilities have become risk averse to new rate-based electric generating capacity. Some, in fact, have stated that they intend to buy new capacity rather than to build new rate-based plants.

The reason for such reluctance by utilities to respond rapidly to growing demand is the generally unfavorable state regulatory treatment afforded utilities in the 1970s and early 1980s. Boldness by utilities to meet perceived new capacity needs has not been rewarded, but rather penalized with large rate disallowances associated with over-capacity, cost overruns and construction delays -- much of it associated with regulatory changes. In fact, Morgan Stanley Co. has estimated that state regulatory disallowances over the past five years amount to $13 billion or about 10% of all utility capital investments during this period.

Furthermore, many state regulators are now espousing new concepts such as integrated resource planning, least-cost power planning, and competitive bidding strategies. The implication of these new policies is clear -- traditional rate-based power plant investments can no longer be presumed to be prudent. For if rate-based investments are determined by regulators to be suboptimal, in the context of integrated resource plans or least costly strategies because they were not competitively bid, then portions could be disallowed. In fact, 14 states now allow or require competitive bidding for new generating capacity and another 12 have programs under consideration. Thus, while some utilities are being pressured by their state regulators to purchase new capacity through competitive bids, many others are looking to purchasing power from wholesale power generators, with appropriate PSC approval to shield themselves from potential disallowances.

In order to provide both utilities and electric consumers with new, viable supply options, it is essential that an independent wholesale power industry be permitted to develop. While the 1978 passage of PURPA has resulted in a narrow class of wholesale power generators (i.e, cogenerators or small power producers), there are serious technical restrictions to qualify for PURPA status which permits up to 50% ownership in plants without onerous SEC regulatory requirements of PUHCA. Thus, to create a viable independent electric generating sector, PUHCA must be amended to eliminate restrictions on ownership of wholesale electric generators.

S. 406 would increase these wholesale supply options by eliminating a 10% maximum ownership limit that is arbitrary, economically indefensible and clearly not in the public interest. Specifically, the legislation would permit the entry of any qualified person into the independent wholesale electricity generation business, regardless of power plant size or whether it cogenerates steam, without causing PUHCA jurisdiction by virtue of that ownership.

Simply put, the present inability of wholesale power generators to meet growing electricity needs is harmful to the nation's electric consumers because it is depriving them of viable and economic electricity supply options. Furthermore, to the extent such supply options are superior to other available options, the competition for generating capacity resulting from the removal of PUHCA constraints will certainly benefit U.S. electric consumers.

In summary, wholesale competition can be a valuable benefit for utilities and consumers, and wholesale generators should not have to labor under the arbitrary statutory and regulatory constraints imposed by PUHCA and only partially relieved by PURPA.

The Efficacy of a Wholesale Generation Alternative

A logical question to be asked by members of the Committee is why are there so many utilities that support S. 406 and so many others that oppose it? I believe the answer is in the differing views of utilities concerning the desirability of increased competition.

I support S. 406 because reforming PUHCA is a necessary step that Congress must take so that utilities can have expanded options to meet their growing demand for electricity.

Some utilities question whether the status quo should be changed. It is true that our Country's electricity system is the best in the world. However, the experience of the past 10 years has shown that the status quo can and should be improved, particularly in view of the growing tide of state regulatory policies encouraging greater competition.

The utilities opposed to wholesale independent power argue that a fully integrated electricity utility industry is essential to provide reliable service and to insure the "obligation to serve" and that creating a wholesale generating industry separate from the fully integrated utilities will harm electricity consumers.

Those of us in the electric utility industry who support S. 406 agree that reliability of service is a paramount objective; however, we believe that the view of those utilities that oppose S. 406 fails to recognize the reality of experience in related industries as well as our own industry. For example, the natural gas industry has generally three distinct sectors: producing, transmission and distribution. The telephone industry also has distinct equipment suppliers, long-distance carriers and local telephone "distributors." Natural gas and telephone service are just as important to consumers as electricity, yet those industries are largely disintegrated. Nevertheless, their distribution sectors maintain high reliability and a strong service obligation to consumers through reasonable and enforceable contractual relationships with the other industry sectors. Furthermore, many electric utilities today, including most municipals, are primarily distribution utilities which buy most or all of their power under wholesale contracts from other utility and non-utility suppliers without jeopardizing their reliability or obligation to serve.

The argument that alternate suppliers from a wholesale power generating sector will lead to a significant diminution of service obligation or quality is simply an unwillingness on the part of some utilities to recognize or participate in the increasingly competitive environment that is already emerging in our industry, similar to what is occurring in other regulated industries.

This criticism of S. 406 presumes that opening up wholesale generation competition would cause problems of reliability of power supply. The criticism is based on the premise that a non-utility wholesale generator does not have any obligation to serve and is only in the business for financial gain and, therefore, does not have to respond to utility requirements, even those that might arise in an emergency.

This argument is very weak. There is plenty of data to demonstrate the reliability of independently-owned power plants. Many of these plants are owned and operated by large multibillion dollar corporations such as Dow Chemical, Enron, Coastal, Bechtel, Combustion Engineering and many others with significant energy expertise. My own company's experience with non-utility generation along with our experience on the natural gas side of our business shows that such generation can be very reliable and successfully integrated into a utility supply system.

Just as a vertically integrated utility has rules of procedure and operation for the various power stations it owns and operates to assure the reliability of electricity delivery, so can contracts between a utility distributor and a wholesale generator be so structured to assure an adequate degree of system reliability. It's simply a matter of two parties entering into a contract and agreeing to terms that will provide the right incentives and penalties to assure successful performance. Moreover, in the case of wholesale generation, incentives to perform well are strong since failure to meet certain standards would trigger financial penalties, including non-payment of capacity charges, that are generally equal to or more severe than those borne by utility owners of rate-based plants. Furthermore, a prudent utility purchaser of power will create a diversity of supply sources and contractual relationships to assure reliability if any one or two projects fail to perform.

Integrated utility ownership is one way of achieving reliability, contracting is another. Each utility must make its own decision about the best means it has to meet its system reliability needs. Some may choose either extreme, all purchase power or all integrated utility ownership. I believe that some combination is likely to be the most prevalent. However, the real point is that the choice can only benefit those who wish to take it without harming the others who decided not to take advantage of this option.

Traditional utility critics also suggest that S. 406 would break up the successful regulatory-utility compact that has helped establish our Country's electricity supply network. Nothing could be further from the truth. For one thing, S. 406 does not compel any utility to purchase wholesale power if it chooses not to do so. It merely provides a new option. However, the enactment of S. 406 and the resulting increase in supply options made available to utilities could help those utilities which choose to take advantage of it better defend their supply procurement decisions.

Another criticism of S. 406 is that it would lead to the de-facto confiscation of utility transmission lines by non-utility wholesale generators that could ultimately displace the existing utility power plants as the suppliers of power for end users. I frankly regard this criticism as a red herring.

First, it is true that the existence of non-utility generators as a source of wholesale supply for utilities cannot become viable unless such generators are connected to the grid. Thus, a utility wishing to purchase power from a wholesale generator has the same incentive to ensure transmission availability as it does for its own generators. In this regard, there is nothing in this legislation that would force utilities to relinquish transmission capacity used to serve their customers in favor of wholesale generators. Furthermore, to the extent capacity is available, many utilities are now coming to consider their own transmission systems as potential revenue sources that can profitably provide a service that would link a wholesale power supplier with a wholesale power customer. The profit for such services, of course, would come only if the utility that owns the transmission system agrees to provide such service to a customer willing to pay a fair price for that capacity.

Second, it is clear in reading the language of S. 406 that it does not force the purchase of power. If a utility has no need for future capacity, there is no requirement for it to purchase additional power to displace its current generation resources. Similarly, there is nothing either in S. 406 or in current law that would force a utility to open its transmission system to third-party access if it chooses not to do so.

What those of us who support S. 406 believe is that the current regulatory system can be improved by removing an impediment to wholesale power supply sources and letting them compete for sales of electricity to utilities that need and want the capacity.

Essential Elements of PUHCA Reform

S. 406 contains the essential elements of PUHCA reform; namely:

-- Creation of a new class of exempt wholesale generators (EWGs) that would be exempt from the purview of PUHCA.

-- Requiring that existing utility generation cannot become exempt without state regulatory approval so as to protect existing plants from removal from direct state public utility commission jurisdiction.

-- Ensuring that all potential owners of exempt wholesale generators (utility affiliates, non-utilities, registered and exempt utility holding companies) can qualify on a non-discriminatory basis so as to ensure fair and equal opportunity.

-- Ensuring that ownership of, or purchasing power from, an exempt wholesale generator is purely voluntary so that any utility can participate or not participate in purchasing wholesale power.

Issues That Should Not Be Included in Legislation

First, some have suggested severe or even total ownership restrictions on utilities' affiliates qualifying as EWGs in their own traditional service area. Such a restriction would be both unfair and harmful to electric consumers. First, many regulators are forcing utilities toward competitive bidding to ensure the most economic outcome for customers. If utilities are prohibited from participating in providing power in their own service territories as wholesale generators, then they are effectively put in a liquidation mode unless they choose to become builders elsewhere. Furthermore, by eliminating a utility from the competition, the consumer would be seriously harmed by eliminating one of the strongest and most experienced competitors.

It should be noted that adequate authorities already exist, and will continue to exist with S. 406, at both FERC and state public utility commission levels to ensure that no abuses occur. In approving the EWGs wholesale rate, FERC has a responsibility to ensure "just and reasonable" wholesale terms and if there were better terms with another EWG that was unfairly squeezed out, there would be ample opportunity under existing law to disapprove the proposed utility affiliates rate. Furthermore, states have the authority or the ability to implement it, to ensure that utilities can be penalized for power contracting practices which are determined to be injurious to ratepayers as a consequence of discrimination or any other reason.

Second, some have suggested that if utilities or their affiliates are allowed to compete as EWGs then it is necessary to require in legislation, such as S. 406, that utility affiliates' books and records be subject to state public utility commission review. This is totally unnecessary because all utilities' books and records are already subject to audit by state public utility commissions and any transaction between a non-utility affiliate and a utility must appear on the utility's books. If the state public utility commission is not satisfied that the transaction is unsubsidized, then the public utility commission already has the statutory authority power to disallow it in the utility's rates.

A final issue relates to transmission access. Some outside our industry would suggest that you can't have wholesale generation without broad mandatory transmission access. I don't agree with that. I believe that a voluntary wholesale system is not only adequate but necessary. A number of very legitimate technical constraints on electric transmission capacity exist in many parts of the country. Electric transmission systems were not constructed as a national grid, unlike the interstate gas pipeline system. The interconnections between utilities were built largely after the fact for reliability reasons. With the growth in demand and generation that we've seen in the last five years, and with only relatively modest growth in new transmission construction compared to the load growths, we can't completely control flows and capacity. These vary from day to day, depending on the utilities' loads, and one can't always send the power where one wants to because of loop flows and one can't always ensure that a certain amount of capacity can be available every day.

Because of this and the great variety of different physical situations that exist around the United States in terms of transmission capacity, it is impossible to mandate access on a broad scale without affecting reliability of transmission service. A better approach is a voluntary system with the proper pricing incentives that basically would grant an exchange of limited access in return for price flexibility. However, this need not be addressed in S. 406 or similar legislation since the FERC, through its wholesale ratemaking authority, along with its authority to regulate wholesale power transactions, already has full capability to deal with access to transmission systems if it were to conclude that a party to a wholesale contract was unfairly using its transmission system. This issue is clearly within the purview of the FERC and ample statutory authority exists to deal with it.

Summary

In summary, Mr. Chairman, enactment of PUHCA reform such as that provided for in S. 406, is very much in the public interest because of the improvements in the efficient delivery of wholesale power that would result. The legislation is simple in its scope. It does not compel any utility to do anything -- and certainly nothing that would harm customers. To the contrary, enactment of S. 406 would help the system work better by providing new options.

Thank you very much.

The CHAIRMAN. Thank you, Mr. McCormick.
Mr. Willrich.

STATEMENT OF MASON WILLRICH, PRESIDENT AND CHIEF EXECUTIVE OFFICER, PG&E ENTERPRISES, SAN FRANCISCO, CA

Mr. WILLRICH. Mr. Chairman and members of the committee, my name is Mason Willrich, and I am the CEO of PG&E Enterprises, which is a wholly owned subsidiary of Pacific Gas & Electric Company. I am also on the parent company's management committee.

PG&E has extensive experience in purchasing electric supplies from independent power producers. We presently purchase power from 475 qualifying independent power projects which represents 3,600 megawatts of installed generating capacity, and we forecast that we will be purchasing 4,800 megawatts of independent power capacity in 1995.

PG&E Enterprises along with Bechtel have formed the PG&E-Bechtel Generating Company, and this company's purpose is to develop and own and operate independent power projects throughout the United States outside PG&E's service territory.

The PG&E-Bechtel Generating Company has currently one project under construction and about 1,300 megawatts of power products under intensive development. So, from the perspective of a utility purchaser and the perspective of an independent power producer, we have a substantial interest in the purposes of the Competitive Wholesale Electric Generation Act.

Congress should focus, I believe, on three principal issues in addressing the need for change in the Public Utility Holding Company Act. First, can an independent power industry play a useful role in meeting future needs for low-cost, reliable electric power in the United States?

Second, does existing legislation and PUHCA specifically, does that legislation substantially inhibit the future development of independent power in the United States as a supply option?

And, third, is the Competitive Wholesale Electric Generation Act an effective legislative remedy?

Let me just touch briefly on each on of those issues.

I believe that an independent power industry can play a useful role as an expanding supply option in meeting the electric power needs in the country. As Bill McCormick has pointed out, there is a need now in the Northeast and other parts of the Atlantic region. By the year 2000 there is going to be a need for additional electric generation capacity throughout the United States.

Electric generation is no longer a natural monopoly, if it ever was. Competition is here now. It will not disappear and, furthermore, I think that public policy in the United States has been traditionally aimed toward providing incentives for competition in markets where competition is a better way to go than a natural monopoly.

Since 1978 with the enactment of PURPA, the independent power industry has significantly expanded. It has expanded rapidly, and I would say that the independent power industry has been a major source of bringing competition into the electric generation sector.

It has also been a major source of technological innovation and financial innovation within the industry.

The total electric generating capacity in the U.S. is now approaching 700,000 megawatts, and independent power, as you pointed out, Mr. Chairman, now represents about 26,000 megawatts, or almost 4 percent, and new generating capacity under construction or advanced development in the United States totals about 69,000 megawatts, and independent power represents over 30,000 megawatts of that capacity or more than 40 percent of the capacity that is under development.

So that independent power is here to stay, and it is playing a useful role currently. Significantly qualifying facilities under PURPA are now exempt from compliance with PUHCA, and without that exemption, the independent power industry would have been stillborn.

Several recent studies have indicated that in terms of future supply that independent power can expect to fulfill a role which would be accounting for roughly half of the additional capacity within the United States. So, the industry is poised for expansion, but the full potential from independent power will not be developed through QFs within the constraint of PURPA and so, therefore, there is a need for an amendment to PUHCA.

My second point is that PUHCA does constitute a formidable obstacle to the continued development and expansion of independent power in the country. The burdens of PUHCA are so onerous that if required, I believe, no independent power company could comply with registration under PUHCA and survive as a profitable business.

I think that there are a number of burdens that are imposed, and I will just fasten on the most significant one which is what is fondly called the two-bite rule where PUHCA limits the development or acquisition of independent power projects that are not QFs. Any person who owns 5 percent or more of a public utility as defined in the act is prohibited from acquiring 5 percent of a second utility without prior SEC approval.

The definition of a utility in PUHCA includes a single electric generating plant. Therefore, you would not be able within the constraints of PUHCA to engage in the development and ownership and management of multiple electric generation plants.

There are a number of ways which are also being explored to avoid compliance with PUHCA. Among those are stretching PURPA so that you have cogeneration facilities which are, if at all possible, beyond what is efficient under overall energy policy, and we tend to squeeze projects into undesirable sites.

Let me address the last question which is the Competitive Wholesale Generation Act. I believe that it is a carefully crafted amendment to PUHCA, and I believe that legislation should accomplish a limited number of things. It should exempt entities which generate electricity for sale to electric utilities, it should provide a fair opportunity to compete for all of the potential exempt wholesale generators regardless of ownership or of parentage so that utility affiliates should have a fair opportunity. They should not be favored, but they should not be discriminated against. And it should ensure that electric utility purchases from exempt wholesale generators are voluntary, not mandatory. And I believe that the legislation as you have proposed it accomplishes this result.

May I take just a moment to address the "if-it-ain't-broke-don't-fix-it argument" or should I observe the red light? [Laughter.]

The CHAIRMAN. Well, I tell you what. We will address that more this morning.

Senator McCLURE. He will work that into his first answer.

Mr. WILLRICH. All right. Thank you very much, Mr. Chairman.

[The prepared statement of Mr. Willrich follows:]

BEFORE THE

U.S. SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES

HEARINGS ON

THE COMPETITIVE WHOLESALE ELECTRIC GENERATION ACT OF 1989
(AMENDMENT 267 TO S. 406)

STATEMENT OF

MASON WILLRICH

PRESIDENT AND CHIEF EXECUTIVE OFFICER
PG&E ENTERPRISES

NOVEMBER 9, 1989

Mr. Chairman, members of the Committee, my name is Mason Willrich. I am President and Chief Executive Officer of PG&E Enterprises, a wholly-owned subsidiary of Pacific Gas and Electric Company (PG&E). I am also a member of PG&E's Management Committee.

PG&E is one of the largest investor-owned electric and gas utilities in the United States, with a service territory of 94,000 square miles including a population of more than 10,000,000 people in northern and central California. PG&E has extensive experience in purchasing electric supplies from independent power producers. PG&E presently purchases power from 475 QF independent power projects representing more than 3,600 MW of installed generating capacity, and forecasts that it will be purchasing power from more than 4,800 MW of independent power capacity in 1995.

PG&E Enterprises and Bechtel Enterprises, a part of Bechtel Group, Inc., have formed the PG&E-Bechtel Generating Company. This Company's purposes are to develop, build, own and operate independent power plants and to sell electricity on a wholesale basis to electric utilities throughout the United States.

The PG&E-Bechtel Generating Company currently has one power plant under construction, with completion targeted for the spring of 1990. In addition, we have in later stages of development seven power projects, totaling over 1300 MW. Thus, from both power purchaser and power supplier perspectives, PG&E and PG&E Enterprises have a direct interest in these hearings. PG&E strongly supports enactment of the Competitive Wholesale Electric Generation Act of 1989.

INTRODUCTION

The Public Utility Holding Company Act of 1935 (PUHCA) should be amended by adoption of the Competitive Wholesale Electric Generation Act of 1989 so that electric utilities will have the option of procuring needed additional power supplies in a competitive market from independent, non-utility, power producers. In 1978 the U.S. Congress provided a strong impetus to the creation of the independent power industry by enacting the Public Utility Regulatory Policies Act (PURPA). Independent power, primarily in the form of generation facilities meeting the size, technological and ownership requirements to be classified as Qualifying Facilities (QF's) under PURPA, now accounts for 4 percent of our nation's electric generation capacity, and a much higher fraction in states such as California and Texas. PUHCA, as it now stands, poses a formidable obstacle to efficient development of independent power. Enactment of the Competitive Wholesale Electric Generation Act will remove this obstacle, thereby expanding our nation's electricity supply options while retaining intact the protections against financial and other abuses which PUHCA currently provides.

In considering whether to enact into law the Competitive Wholesale Electric Generation Act, this Committee, the Senate and the House of Representatives should focus on three principal issues:

First, can an independent power industry play a useful role in meeting future needs for electric power in the United States?

Second, does existing legislation, PUHCA specifically, prevent or substantially inhibit the future development and expansion of independent power as a supply option?

And, third, is the Competitive Wholesale Electric Generation Act, as proposed, an appropriate legislative remedy? Would enactment jeopardize other aspects of the national interest in adequate, reliable, reasonably priced electricity?

I will discuss each of these issues in turn.

THE INDEPENDENT POWER INDUSTRY CAN AND SHOULD PLAY AN EXPANDING ROLE IN MEETING FUTURE NEEDS FOR ELECTRIC POWER IN THE UNITED STATES.

Electricity plays a vital and pervasive role in our national economy. Demand for electricity is forecasted to grow at about the same rate as the economy. New electric generation capacity is needed now in New England and other sections along the Atlantic coast, and will be needed in every region of the country before 2000. The cumulative need for additional capacity between now and 2000 will range between 110,000 MW and 300,000 MW, depending on whether demand for electricity increases at a compound annual growth rate of 1.5 or 3.5 percent.

Electricity generation is no longer a natural monopoly, if it ever was, although long-distance transmission and local distribution remain so. New generation technologies, using both fossil and renewable energy resources, are efficient when they are used in power plant sizes that are much smaller than large coal and nuclear plants. Power plants using these new technologies can be constructed in a shorter time than larger plants. They can also be sized to match more closely a utility's growth in demand for electricity.

Many firms have recently entered the electric generation business as independent power producers. The industry is currently comprised of about 140 companies. They compete with each other to sell power to those electric utilities which prefer to buy the additional power they need rather than to construct new plants and produce it themselves.

PURPA, enacted in 1978, provided a framework for initial development of an independent power industry. Significantly, QF's under PURPA are exempt from compliance with PUHCA. Without such an exemption, the independent power industry would have been stillborn.

During the decade since enactment of PURPA, independent power suppliers, electric utilities, and state and federal regulatory commissions have learned a great deal about appropriate ground rules for development of independent power as a major electric supply option. In particular, our experience in California with long-term standard offer power purchase contracts, including payments based on a high 1983 forecast of future oil and gas prices, has led to the conclusion that competitive bidding is a far better way to determine avoided costs under PURPA than forecasted prices mandated by regulation. Fourteen states have adopted, and 12 more states are considering, a variety of competitive bidding schemes as the mechanism for utilities to procure additional power supplies when they are needed, whether from QF or non-QF sources. It is interesting to note that all of the states with identified needs for new generation capacity have adopted or are developing competitive bidding schemes for supplying their needs.

Since 1978, independent power primarily in the form of QF's, has developed and expanded rapidly. Indeed, the independent power industry has become the major source of increasing competition and of technological and financial innovation within the wholesale electric generation market. Furthermore, a growing number of electric utilities are discovering not only that they can buy power more cheaply than they can produce it, but that independent power plants can perform at least as reliably as utility-owned power plants.

The total installed electric generating capacity in the United States is presently about 700,000 MW, of which independent power now accounts for more than 26,000 MW or almost 4 percent. From 1986 to the present about $16 billion has been invested in independent power projects. New generating capacity under construction or advanced development in the United States is 69,000 MW, of which independent power accounts for 30,500 MW or 44 percent. Investment in independent power is forecasted to be about $42 billion during the period 1989-1995.

In conclusion, a substantial independent power industry is in being, and evolving rapidly. Independent power can provide the nation's electric utilities with reliable power supplies at prices established in competitive markets. Independent power is poised for expansion. Several recent studies conclude that independent power could supply half or more of additional electric generation capacity the U.S. will need by 2000. If this occurs, independent power will represent about 12 percent of total U.S. electric generation capacity in 2000.

Independent power is poised for expansion. PUHCA must be changed, however, for independent power to fulfill its promise for electricity consumers. The full potential of independent power cannot be developed through QF's within the constraints of PURPA, and will not be developed by non-QF's unless they are exempted from PUHCA.

PUHCA CONSTITUTES A FORMIDABLE OBSTACLE TO THE CONTINUED DEVELOPMENT AND EXPANSION OF THE INDEPENDENT POWER INDUSTRY.

PUHCA was enacted in 1935 to restructure the electric utility industry in the wake of the general economic collapse in 1929, and ensuing revelations of widespread abuse of financial and monopoly power in the electric utility industry. PUHCA did its job well. The vast bulk of the industry was restructured into numerous utilities, most of which confined their operations predominantly within a single state. PUHCA's burdens are so onerous that there are now only thirteen utility holding companies registered under the Act, compared with 214 utility holding companies in 1938.

PUHCA continues to circumscribe narrowly and regulate intensively the affairs of these few remaining registered utility holding companies, including their lines of business; securities issuances; intrasystem transactions, such as loans, dividends, capital contributions, and operations and services rendered by affiliates; and sales or acquisitions by the holding company of any utility assets or securities. Such all pervasive regulation is fundamentally inconsistent with the financial and operational structures required by a competitive independent power industry. Particularly burdensome is the requirement of prior SEC approval of financial and other transactions which must be closed on expedited schedules if independent power projects are to be successfully developed. Indeed, the burdens of PUHCA are so onerous that, if required, no independent power company could comply and survive as a profitable business.

The theoretical availability of exemptions from PUHCA does not improve the situation for independent power. All of the relevant exemptions are subject to such strict limitations as to geography and corporate structure that they are effectively unavailable to independent power producers. Moreover, the SEC has broad discretion in granting, withholding or revoking exemptions.

Perhaps most burdensome of all, the "two bite" rule of PUHCA limits the development or acquisition of independent power projects that are not QF's. Any person, whether a holding company or not, already owning five percent or more of the voting securities of a "public utility," as defined in the Act, is prohibited from acquiring or creating a five percent voting stake in a second utility without prior SEC approval. The definition of "utility" in PUHCA includes a single electric power generating plant.

Under this PUHCA provision, therefore, an independent power company would be able to develop only one electric generation project without SEC approval. SEC approval would be required before a second project, and approval would be doubtful in view of the "integration" standards of PUHCA if the first and second projects were located in geographically separated areas.

QF's are, and will continue to be, an important sector of the independent power industry. However, in order for an independent power project to be a QF and escape PUHCA, PURPA limits power plant size or requires a steam host for cogeneration. These limitations exclude from the market many of the most efficient projects, especially in areas where industrial steam hosts have already installed cogeneration or are not economically feasible. Restricting independent power to QF projects will thus truncate the future development of the industry.

Efforts to avoid PUHCA by qualifying as a QF under PURPA create inefficient projects. In order to avoid the application of PUHCA, (i) a project will be designed as a cogeneration facility if at all possible even though the most efficient project would involve only electric generation; (ii) a project may be squeezed into an undesirable site just to be near a steam host, adding to costs, causing design and operations problems, and sometimes increasing the environmental impact on the surrounding community; and (iii) multiple partners may be added merely to satisfy PURPA's 50 percent utility ownership limit.

Unwieldy ownership structures adopted to avoid PUHCA will make management of non-QF projects cumbersome and inefficient. PUHCA treats an owner of a non-QF power plant as a "holding company" if it owns 10 percent or more of a single generating project. In addition, the "two bite" rule applies when the owner holds 5 percent or more of the generating company. In order to avoid PUHCA, these rules force project participants to spread ownership and control over 11 or even 21 different owners. To be effective, this device requires that actual control, as well as formal ownership, must be equally diffuse. The result is ponderous management by large and necessarily diverse groups, precluding timely decision making. In a highly competitive market such management seems doomed to failure.

PUHCA precludes the most experienced players from participating fully and effectively in non-QF projects. Experience and substantial players such as utility affiliates and others aiming to develop many independent power projects over time are less likely to be able to satisfy PUHCA's requirements than are small, start-up entities with a single project in view. PUHCA registration may be avoided if those participants in a particular project who have the largest stake in the industry (i.e., those who are planning to take several bites of the apple) are willing to be limited partners. But, in so doing, they relinquish ultimate project control to general partners who are far less capable of developing, constructing and operating power facilities efficiently (i.e., those who will be satisfied with only one bite of the apple). In this way, PUHCA increases the risks on the independent power industry and constrains the potential benefits of competitive power purchases flowing through to the American consumer.

PUHCA substantially inhibits power plant operation and maintenance services for non-QF projects. Under recent SEC staff interpretations, PUHCA may effectively foreclose firms from providing operating services to non-QF power plants in which they invest, even though they may have extensive experience with power plant operations and maintenance. Moreover, firms providing operating services risk regulation under PUHCA, even though they are not owners, if they have managerial control of the facility or are compensated based on the performance of the unit.

Structuring a non-QF independent power project to avoid PUHCA requires significant resources and makes the project more costly. Costs incurred during project development, prior to financial closing and commencement of construction, have a major impact on the economic viability of an independent power project. The time and money required to structure a project to avoid PUHCA and to obtain a no-action letter from the Securities and Exchange Commission can significantly delay financial close and dramatically increase legal fees. These costs and delays substantially unjustifiably reduce the chances of success of many projects in a competitive market where project economic margins are necessarily thin.

Thus, PUHCA is a fascinating maze for lawyers but a nightmare for those trying to build an independent power industry in the United States. In order for American consumers to realize the full benefits of competitive wholesale power markets, the firms engaged in the independent power industry should be focusing their attention on understanding and serving the needs of their electric utility customers. Finding ways through the PUHCA maze is not a productive use of talent in a highly competitive industry.

THE COMPETITIVE WHOLESALE ELECTRIC GENERATION ACT IS A CAREFULLY CRAFTED AMENDMENT TO PUHCA. IF ENACTED, IT WILL ENABLE INDEPENDENT POWER TO EXPAND AND BE MORE EFFICIENT AS AN ELECTRICITY SUPPLY OPTION.

Legislation to amend PUHCA should accomplish the following:

- It should exempt from PUHCA entities which generate electricity for sale to electric utilities. These are called "exempt wholesale generators" in the definition of the proposed Act.

- It should provide a fair opportunity to compete for all potential exempt wholesale generators, regardless of ownership or parentage. Utility affiliates should not be favored, but they should also not be discriminated against.

- It should ensure that electric utility purchases from exempt wholesale generators are voluntary not mandatory.

PUHCA reform need not address other areas. Transmission access is an issue that is already within FERC's regulatory jurisdiction, and FERC is currently considering a variety of new policy initiatives. PG&E is a leader at FERC and elsewhere in the effort to improve the efficiency of wholesale electric markets through its proposal for voluntary market-based pricing for transmission services. FERC has authority to correct abuses of market power by utilities that own or control transmission facilities.

FERC and the state utility commissions also have ample authority to prevent any abuses from self-dealing or cross-subsidies if an electric utility purchases power from an affiliated independent power producer. They have full access to the books and records of the utility and therefore to all records relating to the decision by the utility to purchase from its affiliate. They can disallow expenses deemed imprudently incurred by utilities through power purchases from their own affiliates or other independent power producers. PUHCA, the Federal Power Act and PURPA rely heavily on state commissions to protect consumers of energy utility services, and state commissions have capabilities to do so.

The arguments against the competitive wholesale Electric Generation Act have been considered and are either clearly without merit or irrelevant. It is argued that exempting non-QF independent power producers from PUHCA will shift regulation of a significant amount of power production from the states to FERC since FERC regulates and approves the wholesale transaction. This argument is flawed.

Nothing in the proposed Act would alter the right of state regulatory commissions to prescribe ground rules for power purchases through competitive bidding and to review the prudence of utility power purchases. As Senator Johnston has correctly stated "One must assume serious and prolonged errors in judgment by both purchasing utilities and state regulatory commissions in order to argue that the nation's electric supply would be harmed by enactment of legislation. In other words, if in a given instance IPP power is unacceptable, it simply need not be purchased."

It has been argued that power a utility purchases from an independent producer will be less reliable than power the utility produces in its own plants. Nothing in the proposed Act would alter the fundamental obligation of electric utilities to provide their retail customers with adequate, reliable service at reasonable prices -- whether they rely on kilowatt hours produced in their own plants or purchased in wholesale markets from plants owned by others. Many electric utilities have relied for years on power purchases to meet a significant fraction of their customers' loads.

Specifically, PG&E has had several years of experience in purchasing a significant amount of QF power owned by others. We have found QF power to be as reliable as our own, depending of course on the details of our contractual arrangement with particular suppliers. Furthermore, in the recent 7.1 magnitude earthquake which PG&E experienced in its service area, cogenerators and other independent power producers performed well and played a role in our efforts to rapidly restore electrical service to our customers in the San Francisco Bay Area.

Overall, the reliability of independent power plants should be equal to or greater than utility-owned plants. A utility executive who argues that PUHCA reform will result in less reliable power appears to be doubting the competence of his or her utility in making power purchase decisions.

Finally, it is simplistically argued: "If it ain't broke, don't fix it." This argument ignores completely the dynamic past, present and future of the electric supply industry in the United States.

There is now in being an important independent power industry. There are now technological and economic forces reshaping the entire electric supply industry along more competitive lines. It is in this context that independent power can and should play an expanding role. The electric supply industry will serve our nation well if we anticipate and manage the profound changes that are now occurring and that lie ahead. As a vital part of the infrastructure, we must be a source of solutions as America seeks to survive and prosper in an increasingly competitive global economy.

CONCLUSION

Electric utilities should have the option of buying power from independent power producers rather than generating it themselves. Monopoly should be diminished and competition increased in the nation's wholesale electric generation markets. If this occurs, the predictable results will be a more rapid pace of technological advance in the U.S. electric supply industry and lower power costs for American consumers at home, at work and at play. Consequently, speedy enactment of the Wholesale Electric Generation Act is in the national interest.

The CHAIRMAN. We have this set, by the way, on eight minutes so that first round will go for eight minutes.

Mr. Elston.

STATEMENT OF PAUL J. ELSTON, PRESIDENT AND CHIEF EXECUTIVE OFFICER, LONG LAKE ENERGY CORP., INC., NEW YORK, NY

Mr. ELSTON. Mr. Chairman, members of the committee, thank you for the opportunity to testify today. I am Paul Elston, Chief Executive Office of Long Lake Energy Corporation, an independent power producer which builds and operates plants on the East Coast of the United States. The views I express today are my own, but they are also consistent with the views of the National Independent Energy Producers, an association of companies like my own.

We support the amendment to PUHCA. Long Lake was founded in 1980 as a small hydrodevelopment company. In 1987 we began to develop cogeneration facilities. Today we have four plants operating and five more under construction, a total of almost 500 megawatts of capacity.

The competitive power markets in which we participate have changed dramatically in the past two years. Our markets are no longer driven by fuel efficiency, but rather by the need for electric generating capacity.

Utilities which need capacity are actively seeking contract power and are working with state regulators to devise a competitive system under which they may purchase it. We believe we can contribute significantly to meeting this newly recognized need, and we are anxious to do so under a system which is both competitive and fair.

Success in this new environment will depend on our ability to diagnose the needs of utilities and to design a product which meets those needs reliably and efficiently. But Long Lake and other independents are constrained in our ability to participate in this market because of PUHCA.

Let me give you two examples of these constraints. A year ago Long Lake recognized that Virginia Power Company had a severe shortage of summer peaking power. In our winning bid in the competition that they conducted we proposed to build an IPP, a 240 megawatt peaking facility. A cogeneration facility, which was our only other option, would not have worked in Virginia or anywhere else where peaking power is needed because a cogeneration plant must meet the steam requirements of its host and cannot be dispatched as a peaker.

Another example of a restraint occurs in the area of the country which most needs power today, the Northeast. Unlike Texas with its large petrochemical industry, the Northeast does not have large steam users for whom cogeneration is a great source of economic efficiency. Therefore, our ability to participate in this market as cogenerators is growing more and more limited every day.

Now, some utilities would like to keep us in this competitive box. Utilities opposed to PUHCA reform claim that it will lead to the displacement of traditional cost-of-service generation with an untried competitive power market. This view is based on a false premise. Competition is already here today. 33 states, virtually all states with a growing demand for capacity, have adopted or will soon initiate competitive bidding.

All that this legislation does is to create the option for additional supplies to come into the market and to produce additional savings for ratepayers. The states and the purchasing utilities are left free to decide whether it is in the ratepayer's interest for the utility to contract with these suppliers.

The states have opted for a competitive generation market because of the cost overruns and rate shock which occurred in the eighties. The same experience has led utilities to become increasingly reluctant to build new rate-based facilities.

At the same time PURPA brought into the market a vigorous new industry of non-utility suppliers. Their projects give regulators a market-based benchmark by which they can compare the efficiency of cost-of-service facilities.

This is why utilities fear competition. They would rather deal with the regulators than the discipline of market forces. But the inescapable fact is that the competition genie is already out of the bottle, and there is no turning back.

What responsible utility regulator or utility executive would decide to build a new plant today without first asking the question can I get a better deal for the ratepayer by buying the power, by buying the power rather than building new capacity?

Competition in power generation brings many benefits to the consumers. Competition brings new suppliers of capacity into the market enriching the supply options for utilities, driving down costs, and reducing ratepayer risks.

In the 38 bidding RFPs issued to date, bidders have failed to beat the utilities pre-bid benchmark cost on only two occasions. On 36 out of the 38 occasions the independents were offering a better deal to the ratepayer than the utility thought that it could deliver to the ratepayer. This fact shows that competition is reducing costs for the ratepayer and offering other benefits.

In competitive procurements to date, approximately 12 megawatts have been offered for every one megawatt of new capacity requested. This intense competition among suppliers for a limited amount of capacity forces economic efficiencies, encourages diverse and advanced technologies, and rewards smart sighting and fuel procurement.

Some utility critics of competition in generation claim it will reduce the diversity of supply and create excessive dependence on gas-fired facilities. Let me make clear that independent producers share this concern and have no preference for any particular technology. They will respond to the needs of the market.

It is the utilities which control the specifications and terms and conditions of competitive procurements, not the independents. The ratepayer's interest in identifying the most efficient and reliable supplier is also the reason why it makes sense to open the market to non-QF independent power facilities.

QFs constrained by steam hosts and size limitations of PURPA may not be the most efficient suppliers in all cases. Under current law most major investors in non-QF independent power facilities face extensive regulation including financial and reporting requirements and SEC supervision of acquisitions, contractual transactions with affiliates, and the sale of securities.

Therefore, unless a way of avoiding PUHCA regulation is available, it is difficult for a developer to find investors willing to invest.

Now, there are a number of PUHCA avoidance options available, but none of them is entirely satisfactory. These arrangements are costly, time-consuming and inefficient serving no purpose other than avoiding the long arm of PUHCA.

PUHCA was enacted to protect investors and consumers from monopoly power of utility holding companies. Companies like Long Lake do not have monopoly power and do not have the potential to abuse that type of power. If these entities are freed from PUHCA regulation, the end result will be cheaper, more efficient and more reliable electric energy to satisfy the nation's needs.

Now, before closing I would like to briefly discuss three subjects which will be dealt with more extensively in future hearings. The first is the reliability of independent power. Despite assertions to the contrary, the facts indicate that independent power is at least as reliable if not more reliable than utility plants. NIEP will submit documentation of this reality in its written testimony.

The second subject is the potential for abuse of market power by utilities. I commend the committee for scheduling separate hearings on this subject. Any amendment to PUHCA must provide strong safeguards and deterrents against abuse of market power or transmission control. To ensure that this legislation gives the full benefit of competition to consumers, Congress must review FERC's authority, determine that FERC has sufficient authority to protect against abuses, and must ensure that FERC exercises that authority.

The third subject is state regulation. Amendment of PUHCA should not become a vehicle for utilities to avoid state regulation. At the same time it should not subject independent power facilities to rate regulations as if they were utilities.

In closing, I urge Congress to amend the Public Utility Holding Company Act. Competition in the electric generation market benefits the consumer by providing the most efficient, reliable, environmentally sensitive and least cost power supply options. Thank you.

[The prepared statement of Mr. Elston follows:]

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TESTIMONY OF PAUL J. ELSTON
PRESIDENT AND CHIEF EXECUTIVE OFFICER
LONG LAKE ENERGY CORPORATION, INC.

before the

COMMITTEE ON ENERGY AND NATURAL RESOURCES

UNITED STATES SENATE

November 9, 1989

Mr. Chairman and Members of the Committee, my name is Paul Elston. I am President and Chief Executive Officer of Long Lake Energy Corporation, an independent power company headquartered in New York City. Long Lake builds and operates electric and steam power plants.

I am testifying today in my capacity as the President of Long Lake Energy, but my views are consistent with those of the National Independent Energy Producers, an association of independent power companies, which will provide a more comprehensive view of its members' positions in testimony before this committee on November 16th.

Long Lake was founded in 1980 as a small hydroelectric development company. Today, we have four operating hydroelectric plants in upstate New York, a fifth under construction, three more with licenses which we will begin to construct over the next few months, and an additional ten projects under development.

In 1987, we began to develop cogeneration facilities. We have signed six power sales contracts for a total of 410 megawatts of cogeneration on Long Island and plan to begin construction of three of the plants in 1990. We expect commercial operation of these plants in 1991 or 1992.

Although we continue to pursue small hydro and cogeneration and thereby contribute to the fuel efficiency of New York, we realize that the competitive power markets have changed dramatically in the past two years. Our markets are no longer driven by fuel efficiency but by the need for electric generating capacity. Utilities which need capacity are actively seeking contract power and are working with state regulators to a devise competitive system under which they may purchase it.

We believe we can contribute significantly to meeting this newly recognized demand for capacity and are anxious to do so under a system which is both competitive and fair.

Success in this new environment will depend on our ability to diagnose the needs of utilities and to design a product which both the utility executives and regulators see as efficiently meeting those needs. We must propose power plants which are located in the right place to meet load, interconnection and fuel supply considerations. We must propose the right technology and fuel. We must convince them that we can permit and build our plants in a timely fashion. It must be the right size and we must be willing to operate it on their schedule. We see ourselves as a service industry, trying to meet the requirements of our customers, the utility and its regulators. But Long Lake and other independents are constrained in our ability to participate in this market because of PUHCA.

I would like to illustrate why the constraints of PUHCA make little sense in today's capacity driven market by two examples. Long Lake recognized that the Virginia Power Company had a severe shortage of summer peaking power. In its winning bid, Long Lake responded to that need by proposing to Virginia Power that we build for them a 240 megawatt combustion turbine peaking facility. A cogeneration facility would not have worked for Virginia or anywhere else where peaking power is needed because a cogeneration plant must meet its steam load requirements and cannot be dispatched as a peaker. Yet, without a way to avoid regulation under PUHCA, independents are significantly limited to building cogeneration or other small power facilities which do not make sense technically or economically for utilities.

Another example of a restraint to market entry in the absence of an amendment to PUHCA occurs in the area of the greatest need for capacity today, the Northeast. Unlike Texas, for example, with its large petro-chemical industry, the Northeast does not have large steam users for whom cogeneration is a great source of economic efficiency. Therefore, our ability to participate in this market as cogenerators is growing more and more limited.

Some utilities would like to keep us in this competitive box. Utilities opposed to PUHCA reform claim that Amendment 267 to S. 406 will lead to the displacement of traditional cost of service generation with an untried competitive power market. They claim that the traditional system has served us well and ask in effect: "If it ain't broke, why fix it?"

This view is based on a false premise. This legislation will not usher in a competitive generation market. Whether this bill passes or not, a competitive generation market already exists in most states and will continue to grow as the need for capacity expands in the Nineties. Thirty-three states -- virtually all states with a growing demand for capacity -- have adopted or will soon initiate competitive bidding. All that this legislation does is to create the option for additional suppliers to come into the market and produce additional savings for ratepayers. The states and the purchasing utility are left free to decide whether it is in the ratepayers' interests for the utility to contract with these suppliers for new capacity.

To understand why the states have opted for a competitive generation market, we have to review how the idea of electric generation as a regulated utility monopoly was repudiated in the Eighties. Large central station coal and nuclear plants, which gave utilities economies of scale, fell out of favor in the Eighties because of cost overruns, long construction lead times, and environmental concerns. These problems led to rate shock for consumers and cost disallowances for utilities. As a result, utilities became increasingly reluctant to build new rate-based facilities subject to cost-of-service regulation.

At the same time, PURPA brought into the market a vigorous new industry of non-utility suppliers. Their projects gave regulators a market-tested benchmark by which they could compare the efficiency of cost-of-service facilities with contract power options. Competition from these non-traditional suppliers increased the probability of cost disallowances in prudency reviews and made the utilities even more risk adverse.

This is why some utilities fear competition. They would rather deal with regulators than with the discipline of market forces. But the unescapable fact is that the competition genie is already out of the bottle, and there is no turning back. What responsible utility regulator or utility executive would decide to build a new plant today without first asking the question, "Can I get a better deal for the ratepayer by buying rather than building capacity?"

Relying on the mandatory purchase requirement of PURPA, QFs have come forward in such numbers that they have often offered more capacity than utilities needed at a particular time. Many states have turned to competitive bidding as the most efficient means for determining which QFs should be awarded contracts for new capacity. This competitive procurement was preferable to "First come, first served" and other arbitrary allocation systems in which the most efficient and reliable suppliers were selected only by chance.

Competition in power generation brings many benefits to consumers:

-- Competition brings new suppliers of capacity into the market, enriching the supply options for utilities and driving down costs. In the 38 bidding RFPs issued to date, bidders have failed to beat the utility's pre-bid benchmark cost on only two occasions. This shows that competition is reducing costs for ratepayers.

-- Competition also reduces risks for ratepayers. The construction and operating risks of new facilities are shifted from the ratepayers and shareholders of traditional utilities to the developer and financiers of independent power projects.

-- In competitive procurements to date, approximately 12 MWs have been offered for every 1 MW of new capacity requested. This intense competition among suppliers for a limited amount of capacity credits forces economic efficiencies, encourages diverse and advanced technologies, and rewards smart siting and fuel procurement.

Some utility critics of competition in generation claim it will reduce the diversity of supply. They point to the predominance of low capital cost/high fuel cost technologies such as gas-fired cogeneration, in contracts awarded independent power producers and question whether this will make ratepayers vulnerable to fuel supply instability in the future.

Let me make clear that independent power producers share this concern and have no preference for any particular technology. They will respond to the needs of the market. It is the utilities which control the specifications, terms and conditions of the competitive procurements, not the independents. As far as we are concerned, the more varied and flexible the technology and fuel options in an RFP are, the better.

The fact of the matter is that independent suppliers want to give utilities what they want. Like the utilities, they want to deliver the most reliable power at the least cost from the best locations.

The ratepayers' interest in identifying the most efficient and reliable supplier is also the reason why it makes sense to open the market to IPPs as well as QFs: QFs, constrained by the steam host and size limitations of PURPA, may not be the most efficient suppliers in all cases.

Under current law, most major investors in non-QF independent power facilities face regulation as "holding companies" under PUHCA. Registered holding companies under PUHCA are subject to extensive regulation, including financial reporting requirements and SEC supervision of acquisitions, contractual transactions with affiliates, and the issue and sale of securities. Therefore, unless a way to avoid PUHCA regulation is available, it is difficult for a developer to find investors willing to take a large share of stock in a non-QF project. Developers attempting to put together groups of investors or find a general partner to finance a new generating project face a formidable task.

There a number of "PUHCA avoidance" options available to independent power developers, but none of them is entirely satisfactory. One is to design the new facility to meet the requirements under PURPA to become a QF. For cogenerators, this option has induced inefficient investment in token thermal applications and narrowed options for locating facilities close to electric loads and transmission facilities.

The need to co-locate with a steam user in order to be qualifying cogeneration facility is a growing problem. The pressure to develop ever more inventive "PURPA machines" has intensified as the availability of existing steam users for cogeneration facilities is exhausted.

Another option for a developer of a non-QF project who wishes to avoid regulation of investors is to obtain a statutory exemption under Section 3 of PUHCA. The most commonly used exemption is that which is available to holding companies whose activities are "predominantly intrastate" in character. The requirements of this exemption make it impossible for independent producers to use their expertise in financing and constructing geographically diverse generating plants and to locate plants where they are most needed.

Even an exempt holding company, or a minor investor owning less than 10 percent of a generating facility, is subject to the "two-bite" rule under PUHCA. That rule requires SEC approval of the acquisition of 5 percent or more of the stock of a holding company or electric utility if the purchaser already owns 5 percent of another holding company or utility. This restriction discourages the development of numerous power plants by the same company, even within a single state.

Because the above options for avoiding or minimizing SEC regulations are so limited, developers are forced to arrange extremely complex ownership mechanisms, such as sale-leaseback arrangements or voting trusts, or to spread ownership among at least 10 partners to shield investors in new, independent generating facilities from PUHCA regulation. These arrangements are costly, time consuming and inefficient, serving no purpose other than avoiding the long arm of PUHCA.

PUHCA was enacted to protect investors and consumers from the monopoly power of utility holding companies. Over the past five years, however, it has become increasingly clear that the restraints of PUHCA have retarded the orderly development of a competitive power generation market. Companies like Long Lake do not have monopoly power and do not have the potential to abuse that power. If these entities are freed from PUHCA, and remain subject to regulation by FERC under the Federal Power Act, the end result will be cheaper, more efficient, and more reliable electric power to satisfy the nation's energy needs.

Before closing there are three subjects which I would like to discuss briefly since they will be dealt with more extensively by another speaker today or in subsequent hearings.

The first is the reliability of independent power. Despite assertions to the contrary, the facts indicate that independent power is at least as reliable, if not more reliable, than traditional utility plants. This statement applies to the construction as well as the operation of plants. NIEP will submit documentation of this reality in its written testimony.

The second subject is the potential for abuse of market power by utilities. I commend the Committee for scheduling separate hearings on this subject.

Any amendment to PUHCA must provide strong safeguards and deterrents against abuse of market power which could eliminate the benefits of true competition. To insure that this legislation gives the full benefit of competition to consumers, Congress must review FERC's authority, determine that FERC has sufficient authority to protect against abuses of market power, and ensure that FERC exercises that authority.

Independents are particularly concerned about utility control of transmission. Control of transmission should not be used to advantage anyone in the competition for wholesale electricity generation contracts. Any PUHCA amendment should clarify that FERC has the authority to assure that transmission access and pricing are not used to unfairly capture market share of electric generating capacity. Also, in some areas, preemptive rules are required to eliminate the opportunity for abuse.

Congress must also vest in FERC the enforcement capabilities necessary to insure that the free market works and prices are not established by unfair means. We know that establishing and proving that market power or transmission control has been abused will be both a lengthy and costly process. These enforcement capabilities must include remedies which deter abuse of market power and adequately compensate the injured parties.

The third subject is state regulation. Amendment of PUHCA should not become a vehicle for the utilities to avoid state rate regulation. We, therefore, urge Congress to explicitly recognize that state commissions may disallow costs imprudently incurred by a jurisdictional utility in purchases from wholesale generators. These prudency reviews must take place at the time the contract between the utility and the wholesale generator is executed.

Finally, most states have statutes which are designed to regulate the corporate and financial structure of traditional utilities which have distribution franchises, and the ability to raise revenue through their rate structure and to pass through costs to consumers. The organizational and financial burden that these laws would impose on wholesale generators is unwarranted. Wholesale generators do not have pass-through capability. This type of exemption was provided for Qualifying Facilities under PURPA. We, therefore, urge Congress to exempt IPPs from the state corporate and financial regulations which govern utility rates, continuing, however, to subject them to state siting and environmental controls.

In closing, I urge Congress to amend the Public Utility Holding Company Act. Competition in the electric generation market benefits the consumer by providing the most efficient, reliable, environmentally sensitive and least cost power supply options.

A variety of experts agree that our nation will require an additional 100,000 to 150,000 megawatts of new electric generating capacity by the year 2000. This tremendous demand means that we must go beyond the initial success of the PURPA decade. The restrictions on size, location and technology imposed by PURPA on QFs limit the market's ability to provide adequate amounts of efficient, economic energy to meet this demand. By modifying PUHCA to allow for independent power plants to be built along with qualifying facilities and traditional rate-based plants, consumers will receive the benefits of a more competitive system.

The CHAIRMAN. Thank you very much, Mr. Elston. Thank you very much, gentlemen.

Now, we will hear the other side of the argument beginning with Richard Brooks from Central and South West Services.

STATEMENT OF E. RICHARD BROOKS, PRESIDENT AND CHIEF EXECUTIVE OFFICER, CENTRAL AND SOUTH WEST SERVICES, INC., DALLAS, TX

Mr. BROOKS. Thank you, Mr. Chairman, gentlemen. I appreciate the opportunity of being here today to discuss Senate bill 406.

Central and South West Corporation is a holding company, a registered holding company, with electric subsidiaries operating in Texas, Louisiana, Oklahoma and Arkansas.

Eighteen of the 28 years experience I have in this industry have been in engineering, so this morning I would like to give you an engineering perspective of some of the technical and operating problems we think will result if exempt wholesale generators or EWGs facilities are integrated into our system on other than a voluntary basis.

I think Central and South West is a good example of the evolution toward integrated and coordination operation of electric systems. By operating our four electric companies this way, we have achieved a very high level of efficiency. We have a balanced fuel diversification, and we have adequate reserves.

Our fuel diversification is that we have 40 percent of our generation on natural gas, 50 percent on coal and lignite, and 10 percent on nuclear, and we certainly have enough capacity to meet our load and, in fact, we can meet our load for the next eight years, and when it comes time to build more, we certainly are willing and intend to do so.

We think that a utility company must have control over deciding design and operation of generating units. The Central and South West system is a very large system, being over 1,000 miles in length north and south and 600 miles in width east and west.

Of course, in a system that large there are many remote areas and many of these remote areas require power plants being located there for area protection; that is to hold the voltage and their service up to required levels.

I really doubt that an EWG would be willing to locate a unit in a remote area like this because it would not be near load centers, it would not be near fuel sources. It also would require additional transmission wheeling. When a plant is not located where it should be, it can cause wheeling problems. As an example, it is occurring in Texas right now.

The Electric Reliability Council of Texas is an organization of companies, utility companies in Texas that work together and serve 85 percent of the load in Texas. Currently the north-south lines from south Texas to north Texas are operating at full capacity transmitting QF power. This system was built for emergencies, and if an emergency occurs, which would cause and need large blocks of power flowing in the same direction, it could not respond.

However, we have the right to interrupt this QF power which would allow the emergency to be handled like it was designed for.

However, if this power that is being transferred currently were EWG power on a firm contract, it would not be interruptible, so the system could not operate like it was designed.

We think there will be conflicts in the design and construction of EWG units. We construct units with redundancy and extra capacity in pumps, valves, fans, condensers and et cetera. We do not think a profit-oriented EWG would want to build units like this because it costs, of course, additional money.

Of course, the EWG does not have four and a half million citizens depending on them for continued electric service.

We think there will be conflicts in the operation of these units. Central and South West Corporation adjusts its 106 generating units every four seconds to meet the load demand and to provide the cheapest electric service we possibly can. As the load comes up, we come on line with the next most efficient unit. As the load goes down, we back on the least efficient units operating at the time.

We also control spinning reserve. That is keeping additional reserve in the units in case an emergency occurs. We control voltage regulation, frequency control. All of these controls require for the unit to put out less capacity than it actually can. In other words, operate something at something less than 100 percent.

This would, of course, reduce the output of an EWG if they were operating, and we do not think an EWG unit would like to operate under these conditions of course forcing them to have less revenue from the unit.

If the EWG unit is built to the same specifications and operates under the same operating requirements as the utility company, that means, then, that this generator is built for reliability and not built for revenue. If it is built for reliability and not revenue, then should it not be left to the utility company in the first place?

We think that EWGs will proliferate the use of natural gas. In 1973 Central and South West Company's generation was fired 100 percent by natural gas. And we developed an off-gas strategy and today our generation, as I mentioned, is 40 percent natural gas.

Now, we are not anti-gas. We live in the gas fields, and they are our customers. We just do not want to be too dependent upon that as we have been in the past. However, in the face of that, we still will grow to 55 percent dependency upon natural gas by the turn of the century in ten years and grow from the use of 600 million cubic feet today to over a billion cubic feet per day by the end of the 1990s.

We think that undercapitalized EWGs will be vulnerable to the gas price increases we experienced in the 1970s, and there is an exhibit attached to my testimony that shows that the cost of gas to the Central and South West system increased 1,200 percent between 1973 and 1983, and one of our companies, Central Power & Light Company, experienced an increase of 1,600 percent.

We doubt than an EWG can withstand this kind of impact from a fuel increase cost, of course, unless the utility company and its customers are tied to that extremely high cost of the fuel. If that happens not only would our customers be paying this high cost but we would, again, be dependent upon natural gas like we are trying to avoid.

I guess it is ironic that a little over ten years ago Congress enacted the Fuel Use Act because of the fear of the high price of natural gas and the unavailability of natural gas. We think this bill will accelerate us toward the same problem again.

Of course, the purported answer to all of these problems except that of the substantial fuel problem we have talked about is that all of these problems can be addressed with a contract and, of course, they can be addressed in a contract, but the fact that you have a piece of paper does not mean that there will not be defaults by the EWGs. It places the utility company in a policing position to ensure that all of the items in the contract are abided by.

And, of course, regardless of whether the EWG defaults in a minor or a major way, the utility company is still responsible for providing the service. We think defaults are inevitable whether we are talking about not obeying a simple operating or protecting scheme or whether we are terminating an operation because it is no longer economical.

Gentlemen, we think problems will occur for a very basic reason, and that is that the two strategies we are talking about, the strategy of operating for a profit versus the strategy of operating for reliability are not compatible unless they are the responsibility of the same entity. Thank you.

[The prepared statement of Mr. Brooks follows:]

NOVEMBER 9, 1989

STATEMENT OF E. RICHARD BROOKS

BEFORE THE SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES

ON

S.406: THE COMPETITIVE WHOLESALE ELECTRIC GENERATION ACT OF 1989

Good morning Mr. Chairman. My name is Richard Brooks. I am President and Chief Executive Officer of Central and South West Services, Inc. and Executive Vice President of Central and South West Corporation, a registered public utility holding company. My company, Central and South West Services, performs many services for the Central and South West system's four electric utility subsidiaries, including power dispatching services. These CSW subsidiaries are: Southwestern Electric Power Company, which serves northwestern Louisiana, northeastern Texas and western Arkansas; Central Power and Light Company, serving south Texas; Public Service Company of Oklahoma, operating in eastern and southwestern Oklahoma; and West Texas Utilities Company, serving central and west Texas. All told, Central and South West serves over 4 million people in a widely diversified service area covering 152,000 square miles.

I appreciate the opportunity to testify on S. 406, the Competitive Wholesale Electric Generation Act of 1989. As a member of the Electric Reliability Coalition, Central and South West supports the coalition's position against the bill. I would like to offer an engineer's perspective on the technical and operational problems that we foresee in attempting to integrate a significant number of Exempt Wholesale Generators (EWGs) into a highly coordinated system like CSW's.

The CSW system is a good example of the evolution of electric utilities toward greater integration and coordination. Prior to 1976 the four CSW utilities planned and operated pretty much independently. Each company planned for and built its own generating units, and there was no centralized dispatching on the system. Historically, there had been little or no economic reason to do otherwise. However, as fuel costs escalated and our operating companies added coal and lignite units, it became clear that closer coordination would yield great efficiencies.

We have made great strides. Through joint planning and the efficient sharing of generating facilities, CSW has achieved a comfortable reserve margin, while diversifying our fuels portfolio. Over the past 10 years we have built eight new lignite/coal units at a cost of $2.0 billion, and have installed shares of two nuclear units at a cost of $ 2.3 billion. In the process, we have enabled the CSW system to achieve approximately 60 percent non-gas use, with one of our operating companies, SWEPCO, moving from total reliance on natural gas to a present 88 percent reliance on coal. The addition of 600 MW through projected repowering of six existing gas-fired plants will give CSW ample capacity to meet demand in its service area through the turn of the century.

At the same time, we have established close coordination and centralized dispatch. Every four seconds, our computers monitor demand on the CSW system and adjust generating output on each unit to achieve the most efficient and lowest cost mix of power. Even more important, centralized control makes our system resilient when problems arise. We are particularly proud of the CSW system's performance during crises over the last several years, including the unprecedented icestorms that struck Oklahoma during Christmas 1987.

Our experience convinces us that a utility must have complete control over the siting, design and operation of generating units if it is to provide reliable service at lowest cost. We have dispersed generation capacity in our extensive service area in order to provide necessary reserves throughout the system and area support to remote locations. EWGs will want to locate where a site is available or to be close to gas supplies or potential wholesale or industrial loads. If not properly located, EWG capacity will be of far less value in helping a utility meet area reserve requirements, and could even present serious problems. For example, on the ERCOT system (which handles 85 percent of the electric energy delivered in Texas), the main north-south transmission lines, which were built solely for reliability, have very little reserve capability. Power from an independent generating unit connected to our system or to another utility's, if not under tight control, could load those lines to capacity, leaving no margin for system response to loss of a generator or transmission line elsewhere.

We also foresee a real conflict between EWG interests and the utility's in the design and construction of generating units. We build plants that have the proper level of component capacity and redundancy in everything from boiler feed pumps to valves to blower fans. These features cost more, but are essential for the best combination of economics and reliability. A highly-leveraged EWG may be unwilling or unable to build plants to utility standards. The only alternative would be for the utility to produce extremely detailed specifications for EWG units, which would then have to be monitored and enforced.

We absolutely have to have generation we can count on. This was brought home to us during the record winter cold in 1983. During that period of peak demand, the entire ERCOT system would have faced blackouts if even one additional generating unit had gone down. Almost all of the gas-fired units in ERCOT were on emergency or alternate fuels. Had any unit then operating on alternate fuel not been able to do so, ERCOT would have experienced blackouts from load-shedding.

Operationally, we could not use EWG power reliably or economically unless it is dispatchable to the same degree as our own capacity. Our central control center, in combination with the operating companies' control centers, adjusts output from the 100+ units on the CSW system every four seconds in order to achieve least-cost power, maintain spinning reserves, and control voltage, frequency, and synchronicity. We are able to cycle plants up and down to follow demand as efficiently as possible, increasing generation on the more efficient units as load increases and backing down generation on the less efficient units as load is decreasing. Unless EWGs are prepared to submit to this kind of integration -- as distinct from enjoying take-or-pay contracts for maximum output -- they will be difficult and costly for us to utilize.

And even if an IPP signs a contract theoretically putting itself under our dispatchers' control, how can we monitor and enforce minute-by-minute compliance? Even with the most detailed and iron-clad contract provisions, it would be difficult for us to make sure that the IPP does maintenance at the times necessary to protect system operations, or that the IPP follows dispatchers' instructions as carefully, promptly and completely as our own units do. An IPP's neglect of even so minor a detail of operations as maintaining proper relay settings could have disastrous effects, with IPP units prematurely dropping off the system during times of emergency, contributing to the risk of system collapse. After-the-fact litigation to enforce the operating requirements of a contract is no substitute for quick and certain response. These problems will surely arise because the EWG will be interested in maximizing its revenue stream by maximizing output, while the utility is responsible for service reliability.

As an aside, I would add, if EWGs are in fact capable of being effectively integrated in utility operations to the degree required for economy and reliability, then doesn't this really argue for leaving the generation function with the utility in the first place? The only advantage remaining with EWGs is the ability to leverage, which is a false economy.

Finally, we are concerned about the longer-term reliability of EWG power. These facilities will very likely be gas-fired. Experience has taught CSW that it is unwise to rely too much on a single fuel. After 1973, we faced dramatically increased costs due to shortages of natural gas. Several CSW plants still are occasionally curtailed 100% during the winter. Today, while we use about 40 percent gas, almost all of our gas-fired plants can burn fuel oil, have sufficient inventories of oil to provide the generation during curtailments, and, as required by law, are designed for conversion to coal if need be.

It is true that we still burn a lot of gas. But we are far better positioned to withstand gas price escalations than EWGs will be. Our repowering program will require less capital expense than would be required for us (or an EWG) to build a comparable new gas-fired facility. If the price of natural gas escalates to a level that makes repowering uneconomical in the late 1990s, we will change our plans and construct generation fueled by coal or other energy sources. In addition, our ability to contract for gas and the fact that we have multiple gas suppliers tied into our gas plants ensures reliability of our gas supply.

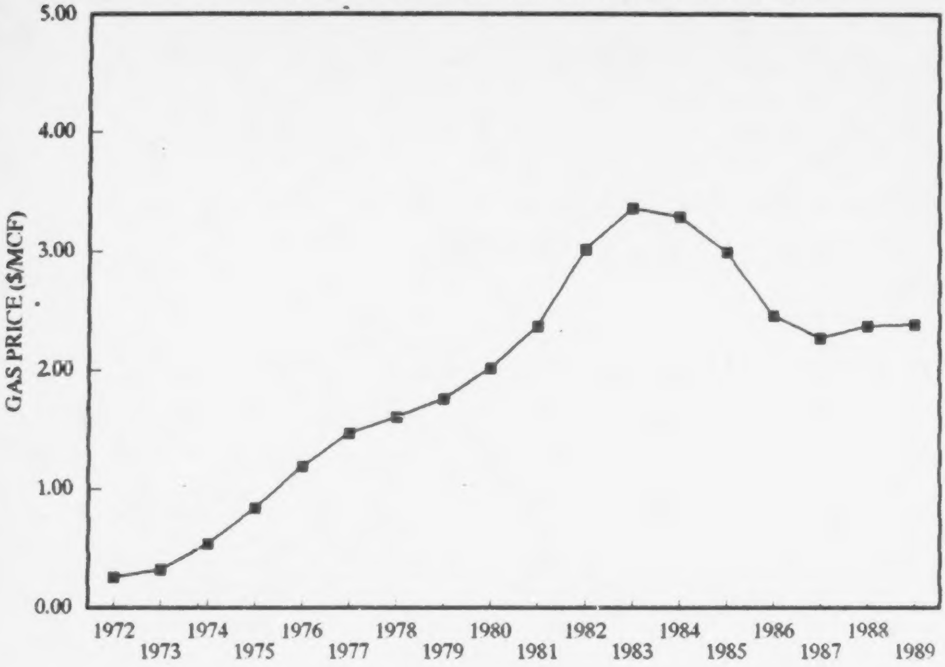
By comparison, undercapitalized EWGs are going to be vulnerable if gas prices fly up like they did in the 1970s. Attached to this statement is an exhibit showing the price of gas to CSW's operating companies from 1970 to the present. As the exhibit shows, the price system-wide increased 1200 percent during that period. For one operating company, the increase was on the order of 1600 percent.

I doubt that many EWGs could weather this kind of financial shock. With little equity investment, defaults will be likely. Utilities will be faced with the prospect of taking over, probably with much delay and legal difficulties, gas-fired projects that we would never build ourselves, forcing our customers to pay an inordinately high price for electric service. Of course, EWGs will certainly try to cushion themselves with fuel-cost escalators. But that kind of contract, like taking over failed projects, would simply lock us into a gas dependence that we have worked hard to change. In either case, we will have been denied the control over fuel selection and type of unit (i.e., base-load vs. peaking) that is essential to a utility's ability to manage the fuel cost and reliability risk.

This is ironic. It was only ten years ago that Congress told us to get off of gas because everyone thought we were running short. This bill will do just the opposite.

Mr. Chairman, as an engineer and utility operations professional, I am greatly concerned about any proposal to foster independent power production. Electric systems are fragile and delicately balanced. The reason they work so well is because generating units are sited, designed and dispatched by a single entity whose only aim is to provide least-cost power while protecting system integrity and reliability. EWGs are not compatible with these requirements.

CSW HISTORICAL GAS PRICES



The CHAIRMAN. Thank, you, Mr. Brooks.

Mr. Drue Jennings, from Kansas City Power and Light.

STATEMENT OF A. DRUE JENNINGS, PRESIDENT AND CHIEF EXECUTIVE OFFICER, KANSAS CITY POWER & LIGHT CO.

Mr. JENNINGS. Thank you, Mr. Chairman.

I am Drue Jennings. I am president and chief executive officer of KCPL. We are not as big as Dick. We serve a 4,700 square mile area in Missouri and Kansas. And that includes most of the metropolitan Kansas City area.

We have got about 3,000 megawatts of available capacity in our system. And on a capacity basis it is about 80 percent fossil fuel, 20 percent nuclear.

However, our energy requirements each year are met about 70 percent coal and 30 percent nuclear. The amount of gas and oil that we burn for flame stability or start-up is not appreciable at all.

I appreciate your invitation to appear and testify here this morning. My company opposes the amendment to PUHCA. And we do support the Electric Reliability Coalition, who likewise opposes the bill.

Mr. Chairman, I admire your continuing concern about the future of electric power in our country and your effort to look for ways to assure that sufficient capacity and system reliability will be here. And I, too, am committed to that long-run health and reliability.

In the 107 years that my company and its predecessors have been in operation in our area, we have never forgotten, nor have we ever failed to meet that obligation to serve. It is the cornerstone of the regulatory obligations we assume.

We take equally serious our obligation to serve in the future. And we have plans in place right now to continue to provide sufficient capacity and reliable service to the over 400,000 customers in our area.

Our plans include a combination of plant life extensions, capacity upgrades for existing units, combustion turbine construction in small increments to meet peak load growth only. Off system purchases, load management, conservation techniques and, ultimately, when I need it, new base load generating capacity.

Mr. Chairman, most of us share the same goals and concerns in terms of future electric service. I do not think you will hear any debate among the six people here this morning within that respect.

But where our views diverge is whether independent power producers can more efficiently produce that power at lower prices to the electric consumer, than can vertically integrated utilities.

The supporters of the legislation, apparently, believe that there is a host of potential competitors armed with superior technologies, managerial skills, or economic efficiencies, who stand willing to meet the capacity needs that the investor-owned utilities, allegedly, have refused to meet. But these companies are not hindered by the prospect of becoming regulated holding companies under PUHCA.

If only the artificial barrier of that act were lifted, they argue, the most efficient generators would succeed. Our potential future capacity problems would be solved and electric consumers would be better off.

And, I submit, that scenario is a bit rosy, and it is an illusion. Because if this law is passed, the successful entries—entry by the Exempt Wholesale Generators into the business of generating electricity would be made based almost solely on an artificial cost of capital advantage. It would be enjoyed, only, by them.

The advantage would not be available to utilities. And certainly is not enjoyed by traditional IOU investment. The cost of capital advantage is based on three factors. First, the differential treatment of debt and equity under federal income tax laws.

Second, the fact that wholesale generators would be parasitic on IOUs capital structures.

And, third, the fact that contracts, the EWGs will have to obtain, if they are to exist, will either explicitly or implicitly, shift virtually all the financial and operational risk associated with power production onto the host utility.

Now, as I will explain later, this latter factor will be—will especially apply under conditions of the nonrecourse financing for the exempt wholesale generator.

Successful entry by those independent power producers would not be based on any efficiencies inherent to them, nor on the concept of a level playing field. As a matter of fact, it is difficult to imagine any true efficiency-based advantage that would enable EWGs to sell power at competitive prices.

I know that the bill theoretically allows utilities to also to set up exempt wholesale generators. But the financing realities result in a situation where any cost of capital advantage to the IOU owned exempt wholesale generator will be immediately offset by a cost of capital detriment to the parent IOU.

Thus, the bill could result and might likely result in two sets of corporate entities. Independent EWGs with an artificially low cost of capital. And IOUs, and IOU/EWG combinations with a higher cost of capital.

The appearance of what may be fair competition, so to speak, is really an illusion.

Well, let us illustrate this. Let us compare the types of financing arrangements and contracts that are likely to emerge, if this bill were to become law. It is generally believed that independent power producers, if they are to exist, must be financed with high levels, 90 percent or more, of nonrecourse debt.

It is difficult to imagine—I am sorry—in turn those levels of debt will be sustainable as a rule, only if the exempt wholesale generator has the benefit of long-term life of facility, take or pay contracts with cost escalator clauses.

Contrast that with the capital structure of a utility. My company is not a registered holding company under PUHCA. It is not the SEC that requires my company to be financed by 49 percent equity, as it was in 1988. It is not PUHCA that has resulted in an average debt ratio, as reported by the Office of Technology Assessment, of about 50 percent for IOUs in 1987. It is the private market that requires those capital structures, and that makes sense from an economic standpoint.

There is an enormous amount of risk associated with utility plant investment. These are capital intensive investments, where equipment is highly specialized, is completely immobile. And, where fuel costs and demand are uncertain over the life of that facility, which can extend for several decades.

If a corporate entity is able to sustain very high leverage in such an environment, it is only because the enormous risk is shifted from that entity and on to someone else. Otherwise, the risk would far outweigh the tax advantage of debt. The leveraged entity would have to have a higher cost of capital, because of higher interest rates to recognize it.

Lacking any true economic efficiencies, the leveraged entity could not compete. To the extent that exempt wholesale generators are successful, it will be, because the contractual arrangements I have just described result in all the risk being born by the utility. Otherwise, what kind of corporate entity could survive in isolation with a 90 percent debt structure.

It matters not that the EWGs debts nonrecourse to the utility. We have the obligation to serve. We depend on available capacity. If an IPP project fails in the development stage, we have to immediately react to make alternative arrangements to replace that plan for capacity.

Worse, if the IPP fails after becoming operational, we have to immediately make up the short fall, most likely by trying to acquire and operate his facilities.

Because of those risks, the credit rating agencies, Moody's, Standard and Poor's will attribute, impute the EWG's debt directly to the IOU raising its cost of capital. The EWG as a separate corporate entity will have a lower cost of capital and appear to be competitive, cheaper anyhow, but only because the associated cost of risk were transferred to the utility.

And when that happens to me, it affects all my capital requirements, not just the generating equipment that I must own and operate, but my transmission, my distribution, my substations, my services, and so forth, making all of them more costly than they need be. Utilities simply do not have that luxury.

Independent EWGs will have a cost advantage due solely to an artifact of the tax code. And I understand that secretary of the treasury, Brady, feels strongly that that double taxation of equity ought to be eliminated. If that were to happen overnight, I dare say, we would probably see few EWGs actually materialize. But I wonder, if we really want to base major policy changes on that quirk in the tax law.

The capital advantage in materials that will be filed later, I understand, with this committee are indicated to be something on the order of 20 percent to 30 percent, which can translate into a 5 percent to 10 percent alleged percent kilowatt hour price variance for the EWG.

Although very real to the EWG, it is an illusion to society as a whole. I do not think our country's electric needs are going to be adequately served by that. And I sure as heck do not need the added risk of doing business in that fashion myself.

Thank you.

[The prepared statement of Mr. Jennings follows:]

November 9, 1989

Before The Senate Committee on Energy and Natural Resources

Statement of A. Drue Jennings
President and Chief Executive Officer
Kansas City Power & Light Company
On
S. 406
The Competitive Wholesale Electric Generation Act of 1989

My name is Drue Jennings and I am President and Chief Executive Officer of Kansas City Power & Light Company. KCPL serves a 4700 square mile territory in Missouri and Kansas, including most of the metropolitan Kansas City area. Of our approximate 3000 megawatts of available capacity, 80 percent is fossil fueled and 20 percent is nuclear. We meet our annual energy requirements with a combination of 70 percent coal and 30 percent nuclear.

I appreciate the Committee's invitation to testify on S. 406, the Competitive Wholesale Electric Generation Act of 1989. For reasons I will explain, our company supports the Electric Reliability Coalition in its opposition to the bill.

I applaud you, Mr. Chairman, for your continuing concern about the future of electric power in our nation, and your efforts to search for ways to assure sufficient capacity and system reliability to meet our nation's electric energy needs.

I, too, am committed to the long run health and reliability of our electric power industry. In the 107 years that KCPL and its predecessors have been in operation, we have never forgotten, nor failed to meet, the obligation to serve that is the cornerstone of the regulatory compact. We at KCPL take equally seriously our obligation to serve in the future and we have plans in place to continue to provide sufficient capacity and reliable electric service for the 400,000 plus customers in our service area. These plans include a combination of plant life extensions and capacity upgrades for existing units, construction of combustion turbines in small increments to meet peak load growth, off-system purchases, load management and conservation, and, ultimately, new base load equipment when needed.

Mr. Chairman, most of us share the same goals and concerns in terms of future electric service. Where our views diverge is whether independent power producers can more efficiently produce power, at lower prices to the electric consumer, than can vertically integrated utilities. Supporters of this legislation apparently believe that there is a host of potential competitors armed with superior technologies, managerial skills, or economic efficiencies, who stand willing to meet the capacity needs that investor owned utilities allegedly will not meet, but are hindered by the prospect of becoming regulated holding companies under PUHCA. If only the artificial barrier of the 1935 Act were lifted, they argue, the most efficient generators would succeed, our potential future capacity problems would be solved, and electric consumers would be better off.

This rosy scenario is an illusion. If S. 406 were passed, successful entry by EWGs into the business of generating electricity would be based almost solely on an artificial cost of capital advantage enjoyed only by independent EWGs. This advantage would not be available to utilities that set up EWGs, and certainly is not enjoyed by traditional IOU investment. This artificial cost-of-capital advantage is based on three factors. First, the differential treatment of debt and equity under the federal income tax laws. Second, the fact that EWGs will be parasitic on IOUs' capital structure. And third, the fact that the contracts EWGs will have to obtain if they are to exist will explicitly or implicitly shift virtually all financial and operational risk associated with power production onto the utility. As I will explain, this latter factor will apply especially under conditions of non-recourse financing for the EWG.

Successful entry by EWGs would not be based on any efficiencies inherent to them, nor on the concept of a level playing field. It is difficult to imagine any true efficiency-based advantage that would enable EWGs to sell power at competitive prices. I know that S. 406 theoretically allows utilities also to set up EWGs. However, financing realities result in a situation where any cost-of-capital advantage to the IOU-owned EWG would be immediately offset by a cost of capital detriment to the parent IOU. Thus, S. 406 will result in two sets of corporate entities--independent EWGs with an artificially low cost-of-capital and IOUs and IOU/EWG combinations with a higher cost-of-capital. The appearance of fair competition under S. 406 is an illusion.

To see this, let's consider the types of financing schemes and contracts that are likely to emerge in a post-S. 406 world. It is generally believed that IPPs--if they are to exist--must be financed with high levels, 90% or more, of non-recourse debt. In turn these levels of debt will be sustainable, as a rule, only if the EWG has the benefit of long-term, life-of-facility take-or-pay contracts with cost escalator clauses.

Contrast the capital structure of a utility. My company is not a registered holding company under PUHCA. It is not the SEC that requires my company to be financed by 49 percent equity as it was in 1988. It is not PUHCA that has resulted in an average debt ratio, as reported by the Office of Technology Assessment, of about 50 percent for IOUs in 1987. It is the private market that requires these capital structures for utilities. And this makes sense from an economic standpoint.

There is an enormous amount of risk associated with utility plant investment. These are capital intensive investments where equipment is highly specialized and completely immobile, and fuel costs and demand are uncertain over the life of the facility. If a corporate entity is able to sustain very high leverage in such an environment, it can only be because the enormous risk is shifted from that entity and onto someone else. Otherwise, the risk would far outweigh the tax advantage of debt and the leveraged entity would have a higher cost-of-capital because of high interest rates. Lacking any economic efficiencies, the leveraged entity could not compete.

To the extent that EWGs are successful, it will be because the contractual arrangements that I just described result in all risk being borne by the utility. Otherwise what kind of corporate entity could survive in isolation with a 90 percent debt structure? What kind of truly competitive market could exist where all of the separate competing entities are highly leveraged?

It matters not that the independent EWG's debt is non-recourse to the utility. The IOU has an obligation to serve and depends on available capacity. If an IPP project were to fail in the development stage, we would immediately have to make alternative arrangements to replace the planned-for capacity. Worse, if the IPP fails after becoming operational, we would immediately have to make up the shortfall, most likely by attempting to acquire and operate the EWG.

Because of these risks, the credit rating agencies -- Moody's or Standard & Poor's -- will attribute the EWG's debt directly to the IOU, raising its cost-of-capital. The EWG as a separate corporate entity will have a lower cost-of-capital and therefore be competitive, but only because the costs associated with risk are transferred to the utility. And the IOU's higher cost-of-capital affects all its capital requirements -- not just generation, but transmission, distribution, services, etc. -- making all of these facilities more costly than need be.

I want to emphasize that the utility does not have this luxury. If it sets up an EWG, the debt will have a direct balance sheet effect on the parent. The utility has nowhere else to transfer the risk. For my company, the buck stops here.

Independent EWGs will have a cost advantage due solely to an artifact of the tax code that treats one form of financing different from another. I understand that Secretary of the Treasury Brady feels strongly that the double-taxation of equity should be eliminated and that the corporate and individual tax systems should be integrated in this regard. If S. 406 became law and simultaneously Secretary Brady were successful in his endeavors on the tax front, I dare say that one would see very few EWGs actually materialize. This fact ought to give us pause. Do we really want to base future capacity on a feature of the tax code that most corporate executives and academics believe is outmoded and in need of change?

Just how big would this cost of capital advantage be for EWGs? I understand that an economic study prepared for ERC shows that a highly-leveraged EWG would enjoy a 20 to 30 percent capital cost advantage over a traditional IOU or an EWG/IOU combination. This translates to a 5 to 10 percent per kilowatt hour price advantage at rates of return comparable to those received by utilities. This cost advantage, although very real to the EWG, is an illusion for society as a whole. It can be had only by imposing new cost on utilities and their ratepayers.

The country's needs for electric power will not be served by allowing the entry of new participants whose viability is based only on artificial factors having nothing to do with the economics of electricity production. There are many substantial questions about whether and at what cost EWGs could be integrated into existing utility systems without jeopardizing the coordination which is the key to least-cost power and reliability. These questions become even more acute when the very existence of EWGs is predicated on artificial cost advantages and risk shifting.

The CHAIRMAN. Thank you, Mr. Jennings.
Mr. Paquette.

STATEMENT OF JOSEPH F. PAQUETTE, JR., CHAIRMAN AND CHIEF EXECUTIVE OFFICER, PHILADELPHIA ELECTRIC CO.

Mr. PAQUETTE. Thank you. Good morning, Mr. Chairman, and members of the committee.

I am Joseph Paquette, chairman and CEO of Philadelphia Electric Company. I have been employed in the electric utility business for over 33 years. All that career has been with Philadelphia Electric, except for two years, when I worked for Mr. McCormick at CMS Energy serving as president, after which I returned to Philadelphia Electric as CEO.

Most of my earlier experience has been involved in finance, accounting and rate regulation activities. And I appreciate this opportunity to comment on the amendment to Senate Bill 406.

My company is a member of the Electric Reliability Coalition. A group of 37 investor-owned electric utilities located throughout the country who together provide over 30 percent of the electric energy supplied by the investor-owned industry.

Philadelphia Electric serves 1.4 million electric customers in the City of Philadelphia and the surrounding counties. In the face of great difficulty we are now bringing on line a 1 million kilowatt nuclear generating unit Limerick No. 2, which will provide us with sufficient generating capacity to meet the demands forecasted through the end of this century.

And, I might add, that we are about eight months ahead of schedule and about $360 million under budget. A budget that was established over four years ago.

Today I would like to summarize my company's position on S. 406, which will support the coalition's opposition to the amended bill.

Mr. Chairman, as you have recognized, an ample, economical and dependable supply of electricity is fundamental to every aspect of the nation's well-being. Senate Bill 406 is an extremely important piece of legislation, which could have a far-reaching impact on the entire electric utility industry, its customers and its shareholders. The bill, therefore, deserves careful evaluation.

As you have stated in introducing the amendment to S. 406, there are many arguments for and against the bill. In judging which arguments are more persuasive, the critical question is, what is really in the best interest of electric customers?

I strongly believe that the public interest would be best served by not enacting Senate Bill 406, because the alleged benefits of EWG competition are illusory, and the potential dangers of loss of coordination and reliability are real.

Mr. Jennings has discussed the artificial cost of capital savings, which might appear to make EWGs competitive through extreme use of leverage and tax benefits.

I concur with his judgment that these artificial savings will be more than offset by increases in the purchasing utilities, cost of capital, and by increased operating cost to address the reliability problems described by Mr. Brooks.

In other words, there is no such thing as a free lunch. Since an EWG would not produce a permanent saving in the cost of capital, I would like to focus on the question of whether an EWG could really build or operate a new generating facility at a lower cost than the local utility could.

Specifically, I doubt, that an EWG could acquire the land for the generating facility at a cheaper cost. In fact, EWG would probably pay more than the utility, who knows the local real estate market in the optimum siting area.

I also doubt that the EWG could obtain the many required permits and licenses more efficiently than the local utility. I doubt that the EWG, lacking the extensive knowledge of local building and environmental codes, could design and engineer the facility more efficiently than the local utility.

I doubt that the EWG as a new entrant in the local labor market could actually build or operate the facility at a lower cost than the local utility And I think this is very important. Our success in completing Limerick under budget was due to a very innovative contract that we had with all the labor organizations involved in the project, which I know the outsider could not have negotiated in the same fashion that we did.

And, finally, I doubt that the EWG could negotiate a more favorable fuel supply contract. Well, then, where does the EWG have a legitimate, competitive advantage?

The only circumstance where the EWG could produce electricity at an initially lower cost, would be where the EWG built an inferior facility at lower cost, or did not maintain it in proper condition, thereby, reducing cost of operation. However, even this short term advantage, would also disappear in the long-run.

Thus, I see absolutely, no economic advantage to our customers from an EWG. In my opinion the only apparent beneficiaries will be the investment bankers and project promoters and developers, who will extract up-front fees, but will not be held accountable for long-run performance.

On the other hand there are many significant, technical and operating risks associated with an EWG as enumerated by Mr. Brooks. I believe these risks are real and fairly predictable.

Proponents of EWGs also claim that the EWG market is willing to take the risk of installing new generating capacity, which utilities may be reluctant to build in the current regulatory environment. This is another artificial argument.

Upon careful analysis it is obvious that the EWGs are actually taking very little risk themselves. Because they are transferring the risk to the purchasing utility by means of take or pay contracts and cost-to-serve adjustment clauses.

To the extent that utility reluctance to install new capacity is a problem, I am sure that utilities would be equally anxious to install new capacity if the regulatory process were altered to give the utilities the same assurances of cost recovery as EWGs are demanding.

To assist the committee in judging whether the public interest would be served best by enactment of S. 406, I would like to put into perspective the possible savings for electric customers if EWGs are permitted to become a major supplier to utilities.

Mr. Jennings has cited a study indicating that an EWG could realize an artificial cost of capital advantage of 20 percent to 30 percent, which could translate into an electricity savings of 5 percent to 10 percent from the EWG source as compared with utility construction of the same facility.

As indicated above, I believe that these savings would be more than offset by increases in the utilities cost of capital and an added operational cost or loss of efficiency. Nevertheless, if one assumes for purposes of argument that a real 10 percent savings is possible with EWG generation, and if a typical utility were to rely on EWGs for all of its increased need over the next 10 years, the utilities customers would see only about a 1 percent difference in their bills by the end of the tenth year with proportionately less savings in the earlier year.

And, I might add, if Mr. Willrich's projection is true that the EWG market will expand only 12 percent by the year 2000, then that number would be decreased to only about a-half-a-percent difference in customer's bills.

And for the typical residential customer in this country, that would mean less than a penny a day in their electric bill.

While, we are always searching for ways to lower our rates, I do not think that a theoretical, and in my opinion, exaggerated rate increase of about a penny a day is worth the significant real risk of seriously jeopardizing the stability and reliability of the best electric system in the world.

Therefore, I conclude that Senate Bill 406 is clearly not in the public interest and should not be enacted.

[The prepared statement of Mr. Paquette follows:]

Statement Of J. F. Paquette, Jr.,
Chairman And CEO,
Phildelphia Electric Company

Before The Senate Committee On Energy And Natural Resources
November 9, 1989

On Amendment 267 to S. 406:
The Competitive Wholesale Electric Generation Act of 1989

INTRODUCTION

Good morning. I am Joseph Paquette, Chairman and CEO of Philadelphia Electric Company. I have been employed in the electric utility business for over 33 years. All of that career has been with Philadelphia Electric except for the 2 years, 1986 to 1988, when I worked for Mr. McCormick at CMS Energy, serving as President, after which I returned to Philadelphia Electric as CEO. Most of my earlier experience has been involved in finance, accounting and rate regulation activities.

My company is a member of the Electric Reliability Coalition, a group of 37 investor-owned electric utilities located throughout the country who together provide over 30 percent of the energy supplied by the investor-owned industry.

Philadelphia Electric serves 1.4 million electric customers in the City of Philadelphia and the surrounding suburbs. In the face of great difficulty, we are now bringing on line a 1 million kilowatt nuclear generating unit (Limerick #2) which will provide us with sufficient generating capacity to meet the demands forecasted through the end of this century.

Today, I would like to summarize my company's position on S. 406, which will support the Coalition's opposition to the amended bill.

SERVING THE PUBLIC INTEREST

As the Chairman has recognized, "an ample, economical, and dependable supply of electricity is fundamental to every aspect of the Nation's well being." S. 406 is an extremely important piece of legislation which could have a far reaching impact on the entire electric utility industry, its customers, and its shareholders. The bill therefore deserves careful evaluation.

As stated by Senator Johnston in introducing the amendment to S. 406, there are many arguments for and against the bill. Proponents cite the potential benefits of competition and the need to install new capacity to meet imminent shortages. Opponents of S. 406 cite loss of economies of coordination, lack of reliability, unwise fuel choices, and over reliance on contractual obligations as a means to obtain capacity.

In judging which arguments are more persuasive, the critical question is: what is in the best interests of our electric customers?

I strongly believe that the public interest would be best served by not enacting S. 406 because the alleged benefits of EWG competition are illusory and the potential dangers of loss of coordination and reliability are real.

ALLEGED EWG SAVINGS

Mr. Jennings has discussed the artificial cost of capital savings which might appear to make Exempt Wholesale Generators (EWGs) competitive through extreme use of leverage and tax benefits. I concur with his judgement that these artificial savings will be more than offset by increases in the purchasing utility's cost of capital and by increased operating costs to address the reliability problems described by Mr. Brooks. In other words, there is "no free lunch."

Since an EWG would not produce a permanent saving in the cost of capital, I would like to focus on the question of whether an EWG could build or operate a new generating facility at a lower cost than the local utility could. Specifically,

(1) Could the EWG acquire the land for the generating facility at a cheaper cost? I doubt it. In fact, the EWG would probably pay more than the utility who knows the local real estate market in the optimum siting area.

(2) Could the EWG obtain the many required permits and licenses more efficiently than the local utility? I doubt it.

(3) Could the EWG, lacking the extensive knowledge of local building and environmental codes, design and engineer the facility more efficiently than the local utility? I doubt it.

(4) Could the EWG, as a new entrant to the local labor market, actually build or operate the facility at a lower cost than the local utility? I doubt it.

(5) Could the EWG negotiate a more favorable fuel supply contract? I doubt it.

Well then, where does the EWG have a legitimate competitive advantage? The only circumstance where the EWG could produce electricity at an initially lower cost would be where the EWG built an inferior facility at lower cost or did not maintain it in proper condition, thereby reducing costs of operation. However, even this short term advantage would also disappear in the long run.

Thus, I see absolutely no economic advantage to our customers from and IPP. In my opinion, the only apparent beneficiaries of IPP will be the investment bankers and project promoters who will extract upfront fees but will not be held accountable for long-term performance.

RISKS TRANSFERRED

On the other hand, there are many significant technical and operating risks associated with an EWG as enumerated by Mr. Brooks. I believe these risks are real and fairly predictable.

Proponents of EWGs also claim that the EWG market is willing to take the "risk" of installing new generating capacity which utilities may be reluctant to build in the current regulatory environment. This is another artificial argument.

Upon careful analysis, it is obvious that the EWGs are actually taking very little risk themselves, because they are transferring the risk to the purchasing utility by means of "take or pay" contracts and cost-to-serve adjustment clauses. To the extent that utility reluctance to install new capacity is a problem, I am sure that utilities would be equally anxious to install new capacity if the regulatory process were altered to give the utilities the same assurances of cost recover as EWGs are demanding.

OVERALL PERSPECTIVE

To assist the committee in judging whether the public interest would be served best by enactment of S. 406, I would like to put into perspective the possible savings for electric customers if EWGs were permitted to become a major supplier to utilities. Mr. Jennings has cited a study indicating that an EWG could realize an artificial cost of capital advantage of 20 to 30 percent which would translate into an electricity savings of 5 to 10 percent from the EWG source as compared with utility construction of the same facility. As indicated above, I believe that these savings would be more than offset by increases in the utility's cost of capital, and in added operational cost or loss of efficiency. Nevertheless, if one assumes for purposes of argument that a real 10 percent savings if possible with EWG generation and if a typical utility were to rely on EWGs for all of its increased need over the next ten years, the utility's customers would see only about a 1 percent[1] difference in their bills by the end of the tenth year, with proportionately less savings in earlier years.

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[1] I assume that a typical utility's increased demand over the next 10 years will equal, at most, 25% of its current total
Continued

While we are always searching for ways to lower our rates, I don't think that a theoretical (and, in my opinion, exaggerated) rate reduction of one percent is worth the significant real risk of seriously jeopardizing the stability and reliability of the best electric systems in the world.

CONCLUSION

Therefore, I conclude that S. 406 is clearly not in the public interest and should not be enacted.

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demand. Multiplying this 25% of total sales x 10% savings x 50% (ratio of generating cost to total cost) = 1.25%

The CHAIRMAN. Thank you very much.

Mr. Brooks, you talked about that the utility ought to be able to control siting location, reliability, all of those things. Since this bill does not require anyone to do anything, could not you design by contract all of those features into your contract before you would take it. Otherwise, turn it down, including reliability, including financial stability, including all of those things.

Could that be done?

Mr. BROOKS. Of course. Of course, you could address any of those issues in a contract. And I would reiterate what I did before that while you can address these in a contract, it still puts the utility in a policing position, number one, to see that it happens.

And, number two, having the contract does not necessarily ensure that no defaults would ever occur.

The CHAIRMAN. Well, of course, it would not ensure that the utility itself would not default. But could you not ensure reliability, location, all of those features that you described by contract, ensure it to the same extent that the utility can ensure itself?

Mr. BROOKS. You could ensure the siting. You could ensure the construction by providing very detailed specifications to which it could be built. And, then, police it to see that it is built that way. And that can be done as it happens.

And, then, when you get to the operation of it, then it becomes much more complicated. And that is where I think the policing issues and the defaults that most surely will occur will happen.

And the rest of that is that, while it can be sited according to requirements in the contract, I do not think that if we site it like we are talking about it, and build it like we are talking about it, we are going to see the kind of savings that have been purported by the EWGs.

The CHAIRMAN. All right, Mr. McCormick, the New Orleans City Council has written me opposing this legislation on the ground that they regulate their utility. And they do not want to use that power to regulate.

How would you answer them? How would they—how can they or should they be able to regulate an IPP on its wholesale power?

Mr. MCCORMICK. Well, every particular state has different state laws.

I would say, first of all that the wholesale transaction, the rate would be determined by the Federal Energy Regulatory Commission, and they, as well as anyone else in the state can participate in that proceeding in determining the wholesale rate.

Following that, many states have laws, including our State of Michigan—I am not familiar with your laws in Louisiana—but many states have the ability to, in effect, allow or disallow the utility to enter into long-term purchase contracts. In effect, they have the power to review those contracts. We do in Michigan.

The CHAIRMAN. You see nothing that would prevent them from reviewing, in effect, the prudency of that purchase?

Mr. MCCORMICK. I see nothing to prevent them from reviewing it. And in addition to that, they have so much jurisdiction over the local utility in other ways, that if they did not like the contract for any number of reasons, I am sure they could exert their regulatory influence to prevent it from being entered into.

There are lots of ways they can disallow things, if they do not believe it is a prudent contract.

The CHAIRMAN. Now, let me ask a more fundamental question. I have heard this legislation criticized on the ground that actually if it moved the power to public utility commissions, and away from utilities, on the ground that PUCs exercising their right to regulate prudence, which I know all utilities feel they have overdone in recent years.

But exercising that right, they could, in effect, keep utilities—in effect, require them to go to IPP purchases, because they have the right to do it, they could, in effect, require them to do it by turning down anything else.

Could you answer that?

Mr. McCORMICK. Well, there are certain parts of the country today, where the local regulatory commissions, the state regulatory commissions are putting enormous pressure on utilities to go to competitive schemes. To make sure, not necessarily force them to purchase from others, but to ensure that if they want to build themselves, that their project is as competitive as alternatives.

There are already a number of states with bidding programs. A number of states are looking at least cost strategies, which would require the utility to take the most economic alternative.

And all of these are putting pressure, in most states, on utilities to ensure that, whether they buy, whether they build or purchase, make or buy, that it is the most economic decision for the rate payer.

I think this is the way things are headed. So, in effect, we are getting that pressure from the states.

The CHAIRMAN. Well, let me ask then the next question. You know I have opposed in the past wheeling.

But, would this legislation, if even though right now it is entirely voluntary with utility to contract with an IPP, if we began it as a voluntary contracting would it tend to follow that, it would then be a requirement of competition?

Mr. McCORMICK. Not necessarily.

The CHAIRMAN. And would that requirement of competition then lead to some kind of wheeling. In other words, let us say the PUC says, okay, you want to purchase from your own IPP this power. How are we going to know that that is a good transaction, unless you open that up to others, in effect, to bid on it?

And if you open it up to others to bid on it, then, you have got to allow them to use your lines to get in the power?

Mr. McCORMICK. Well, there are two separable issues there. One is the question of the power. The utility decides to go out and conduct a solicitation, it in effect has to agree that whoever wins the solicitation will get access to the system to be able to provide the power to it.

And I am not aware of any utility that has gone out for bids. And there have been a number of them who have, that have denied the winner access to their system. I think that is kind of an absurd argument.

The mere fact that they go out publicly and say, we want to get the best bid, how could they come back and say, we are not going to let the best bidder use the system.

The **Chairman**. Well, they would not be bidding. They would be wanting to use their own power. PG&E would want to use Mr. Willrich's company.

Mr. **McCormick**. And in that sense they would have to be able to demonstrate that Mr. Willrich's affiliate has the best deal for the customer. And their commissions would be looking at that.

And if it turns out that it is not the best deal for the customer, there are plenty of ways in which the state commission and FERC can prevent that transaction from going forward.

Senator **Ford**. Mr. Chairman, I apologize for interrupting here. But I think this is important for me personally.

You got two. What if it is mandatory that you take your power from IPPs, rather than your choice now. And, secondly, what if you have to go over somebody else's line in order to secure your energy?

So, if it becomes mandatory that you do it, are you still in favor of it? And, two; what provisions do you have, if you have to go to somebody else's line?

Mr. **McCormick**. No. No, I am not in favor of it if it is mandatory. And there is nothing in this legislation that would make it mandatory.

Senator **Ford**. Oh, I understand, we have not finished it yet, we are just starting. [Laughter.]

Mr. **Paquette**. Mr. Chairman, can I comment on this subject while you are on it?

The **Chairman**. Yes.

Mr. **Paquette**. I think you are really touching on an issue that is at the heart of the opposition to the bill. And that is, that on paper you may make it an option. But in the real world of regulatory affairs, it will become a mandatory provision. I have no doubt about that.

The **Chairman**. Is that because of what I was—the question I had originally? That PUC's would require——

Mr. **Paquette**. They would require us first to bid—and Bill McCormick is right. Competitive bidding is coming and it is here. Opening up the PUHCA legislation to more bidding, I think, just takes us further down a wrong track that the industry is going.

This industry has been built on looking at the long-run. The more competitive bidding we have, the more emphasis will be placed just on price and not on quality and not on the long run. And we will be forced into accepting the low bidder regardless of what it is.

Now, the utility might be able to put in specifications for quality and everything else. But then they might as well build a facility themselves.

Mr. **McCormick**. Mr. Chairman, I think Mr. Willrich has got to respond to that one.

Mr. **Willrich**. Let me have a hand at it, Mr. Chairman. It sounds to me as though what I have been listening very carefully both to the prepared remarks and to the extemporaneous remarks that the utilities which are opposing this concept are, first of all, monopolies that feel themselves threatened by competition and, secondly, they are utilities that do not have an imminent need for capacity.

And from the standpoint of the structure of the industry, there is an option that is available to utilities who want additional capacity to have independent power provide that capacity. It is not something which is compulsory.

In terms of whether a state is going to get together with its utilities within that state and determine that a bidding process is the best way to procure capacity, that is fine.

In California we have—are in the process of developing competitive bidding rules for the next round of generation capacity that we need. We are going to have multi-attribute bidding. It is going to have a very long-term time horizon attached to it that builds on our experience in California.

Our experience is that the QF suppliers—and in the future we hope independent power suppliers—do provide reliable electricity. Our experience is that over the past several years, the QF industry has been reliable through the peaks.

Furthermore, in recovery from the last earthquake——

The CHAIRMAN. By the way, do you all deny that the experience of QFs has been reliable or that——

Mr. WILLRICH. Yes.

Mr. PAQUETTE. I do not agree that it has.

Mr. WILLRICH. I think there is some dispute about that. I am just trying to provide you with some experience.

Mr. BROOKS. We would be glad to give some examples.

Mr. WILLRICH. And that is that in California that we have had reliable power from the supplier, the independent power suppliers, and after the earthquake that we recently went through, there were two sources that we needed very badly that were available. One was our Diablo Canyon nuclear plant, and the other was a number of independent power producers who were there when we got things up and running.

The CHAIRMAN. Let me ask one final question before I turn it over because I do not want to monopolize the questions.

Just tell me, Mr. Willrich, PG&E is the largest utility in the country. It has expertise, it has access to capital, it has everything including great subsidiaries. Why would they want to go to their own subsidiary to build an IPP power producer as opposed to building it themselves if they have access to the capital and expertise?

Mr. WILLRICH. Basically as far as inside California is concerned and our future capacity, we are going to be evolving through a competitive bidding process in which PG&E as a utility will be putting up a plant as a plant that we would build on a utility basis. If that plant is the lowest cost provider within the rules that we lay down, that will be the plant that will be built. It will be built on the utility basis.

If it is not, then the independent power producer will come and provide that power.

Secondly——

The CHAIRMAN. In effect, what can you do better than your parent?

Mr. WILLRICH. Let me just go on because the independent power producer—exactly—the independent power producer—current we are focused outside of our service territory in areas where additional capacity is currently badly needed, and we believe that the

PG&E-Bechtel Generating Company will be highly competitive in a variety of areas of the country.

We would like to have an opportunity eventually to bid inside PG&E's service territory if the State of California adopts regulations where the affiliate of a utility is permitted to bid into its own service territory.

Senator FORD. Mr. Chairman, will they allow you to build a base plant in California? Will they allow you to build a base generating facility in California?

Mr. WILLRICH. Yes, we are building lots of base load plants on an independent power basis in California or a utility basis.

Senator FORD. Is it not mandatory in California that you put it on bids and IPPs? You go to IPPs?

Mr. WILLRICH. We are currently under a mode where utilities can, if they need capacity, can build additional capacity. We do not have final competitive bidding rules adopted yet, but that is the direction that California is head and if the utilities can do it at a low cost, I do not know why they should not do it.

Senator FORD. Well, let me ask you this. Can you build a 1,200 megawatt gas or a coal-fired generating facility in California today?

Mr. WILLRICH. Is that the lowest cost option available?

Senator FORD. I do not know. I am just asking you a question and you can explain it to me. I believe it is broke in California and pretty good shape everywhere else. [Laughter.]

Mr. WILLRICH. I would say, Senator Ford, that it is not broke in California. California is alive and well and that we have a capacity to absorb and to use well independent power.

The CHAIRMAN. Are you talking about Clean Air Act restrictions?

Senator FORD. What I mean—yeah, of automobiles. What I asked you was can you build today a 1,200 megawatt generating facility, coal or gas-fired.

Mr. WILLRICH. We do not have a need for——

Senator FORD. Well, I just asked you——[Laughter.]

I asked you if you needed it, could you build it.

Mr. WILLRICH. If we needed it, we could build it either as a utility or as an independent power producer, Senator Ford.

Senator FORD. What is the different process? Is there a different process or what is the process for you as a utility to build a 1,200 megawatt operation?

Mr. WILLRICH. As a utility you would go through the standard process of getting a certificate of public need and necessity——

Senator FORD. What about the IPP, if you want to go that route?

Mr. WILLRICH. You would have to compete for the——

Senator FORD. You would compete with them?

Mr. WILLRICH. As an independent power producer, I would compete and would have to win a competitive bidding scheme, which would include a variety of factors tailored to the utilities' needs.

Senator FORD. Well, if it is mandatory in this legislation, would you be for it? Mr. McCormick said no.

Mr. WILLRICH. It is not mandatory in the legislation and I do not believe the country is going that way.

Senator FORD. I know, but what if it is? What if it is?

Mr. WILLRICH. If it is, we would have some reservations as a utility.

The CHAIRMAN. Senator McClure.

Senator McCLURE. Thank you, Mr. Chairman.

The CHAIRMAN. By the way, why do we not try to—I tried to go close to ten minutes.

Senator FORD. I give up my first ten.

The CHAIRMAN. We will get back to you.

Senator McCLURE. Mr. Chairman, I know I have more questions than I will be able to get into a ten-minute period, and I am not fussing about that. I just at this time want to ask unanimous consent that we may submit questions for response in writing.

The CHAIRMAN. Absolutely.

Senator McCLURE. I do not want to misstate the position that anyone has taken here, but I do want to understand, and the panel has been excellent. It has been helpful to me.

Mr. Elston, you are a power producer. You are not in the transmission business?

Mr. ELSTON. That is correct, sir.

Senator McCLURE. And you are not in the marketing business?

Mr. ELSTON. That is correct.

Senator McCLURE. You sell to other marketers?

Mr. ELSTON. I sell to utilities exclusively.

Senator McCLURE. Would you support this legislation as introduced or do you see a need for a transmission access policy?

Mr. ELSTON. I believe that the legislation as it stands right now would open up opportunities for IPPs. The only concern I have with respect to transmission access is that we make sure that those that control it not be able to use that transmission access to prevent me from competing; i.e., they not use it unfairly. But, no, I do not believe that the issue is ripe at the moment for the Senate——

Senator McCLURE. It will get riper when there is more pressure on it?

Mr. ELSTON. Well, I do not believe that it is intrinsic in the nature of this legislation that we should deal comprehensively with transmission access.

Senator McCLURE. I understand that, but you said you will not be worried about transmission access so long as they treat you fairly, which means they are going to let you on.

Now, if they say no, they do not want to, then you are going to ask somebody to——

Mr. ELSTON. No——

Senator McCLURE [continuing]. Add a dimension of compulsion.

Mr. ELSTON. Well, I think if I am in utility A's territory and I want to build a plant to sell to utility B, and utility A wants to do the same thing, okay, I do not think that utility A should be able to send the electricity to utility B and tell me that I cannot do that. That is just unfair competition.

Senator McCLURE. And you would like to see that unfairness eliminated by statute?

Mr. ELSTON. I did not say that. I think that I need assurance that there is adequate authority today and if not, then there needs to be statutory authority to make sure that transmission cannot be used for unfair competition.

Senator McCLURE. What you are saying——

The CHAIRMAN. Would the Senator yield at that point?

Would not present FERC rules prevent that, prevent the utility A and utility B situation you just described from happening?

Mr. ELSTON. I have seen strong evidence on the part of some recent FERC decisions that they are focusing very heavily on that question. The problem that I see is that it is a very costly process from my point of view to demonstrate that someone has actually abused their power, and it may take two years or three years for me to do it, and it is after the fact. So, I mean, if you want real competition out there, there has got to be some reasonable assurances that market power and transmission access will not frustrate that. Otherwise, the whole purpose of what we are talking about here will go down the drain.

Senator McCLURE. Let us use just a slightly different hypothetical situation. You want to put a plant in. You are in utility A's territory and you want to supply power to utility B outside that service and transmission area, and you have a competitor who is also bidding to supply to utility B but lies within utility B's territory.

You have got to not only win the competition in the bidding, you also have to get transmission access over the lines owned by utility A in order to be able to compete for marketing to utility B, is that not correct?

Mr. ELSTON. That is correct.

Senator McCLURE. That is inevitably going to be a part of the process unless you always find that situation in which the IPP is located in the territory of the purchasing utility.

Mr. ELSTON. Yeah. I think we have seen in the Virginia competition, for example, Bill Berry decided to purchase some power in that competition from West Virginia because it was the best for his ratepayers, and he was not able to do that because transmission access was not available in that particular situation.

Senator McCLURE. Yeah. Now, again, I do not want to misrepresent or misstate what anybody said but, Mr. Willrich, it seems to me what you are saying is that there are some utilities that are badly managed, and you would do better if you could build in their territory and supply to them.

Mr. WILLRICH. I am not saying that.

Senator McCLURE. It sure sounded that way to me.

Mr. WILLRICH. Not at all. I am suggesting that well managed utilities, when it comes to providing additional capacity, may wish to have the option which this legislation would provide of being able to purchase that capacity rather than make it.

Senator McCLURE. Why would they want that option if, as a matter of fact, you cannot do a better job?

Mr. WILLRICH. It may be that a well managed utility that if we can do it better by supplying it from an independent power producer, they would prefer to buy it.

Senator McCLURE. How can you do it better?

Mr. WILLRICH. By being more efficient.

Senator McCLURE. So, you are a better manager than they are?

Mr. WILLRICH. Not necessarily. It may be under circumstances that there are ways that independent power can do it that utility cannot. It is a question of having the option, Senator.

Mr. **Elston**. Senator, if I could interject—if you look at what has happened in Virginia in real life here, Bill Berry went out for some power, and he bid it and he bought it because it made sense, number one time.

The second time, the same thing. The third time he went out for power and bids came in and he decided that he could build it more cheaply, and he rejected all of the bids. And in that case it meant that the utility could build more cheaply, and they simply reject the bids. And that is the system we are talking about here.

Senator **McClure**. I know a little bit about the decision process that Mr. Berry went through in each of those three cases, and I do not claim to have any insider information—and I do not have. But I think I also detect from each of the panel, whether you are for or against this legislation, that there are real problems with the regulatory process today.

Mr. **Paquette**. I think that is the guts of the issue, Senator. It is not efficiency of independent power producers versus utilities. It is the regulatory process that needs to be straightened out.

Mr. **McCormick**. Senator, I do not completely agree with that. I think the regulatory process in many states is screwed up. I mean—and it is causing a lot of utilities to look at purchasing rather than building because of the risk it entails for those utilities.

But there is a great difference in efficiency among utilities in this country by a factor of two. Some utilities are twice as efficient as other utilities, and what that means is that there is a lot of opportunity to do things better and you will never know how well you can do it until you open it up and make it a free competition.

And, as Mr. Paquette said before, if he really believes that the independent power producer cannot beat him on site location, on design, on labor contracts or anything like that, then he should not worry about this bill because he will beat him every time.

Senator **McClure**. Excuse me, I have got to recapture a little bit of my time here. [Laughter.]

The National Association of Regulatory Utility Commissioners has asked that we add a provision that gives them regulatory authority over contracts, specifically on the face of this legislation, and I would assume that would also mean that under current rules they can say go ahead and add that contract and the IPP builds the plant and then they are really to supply the power and the utility regulatory commission could then come in and say we think that contract was imprudent, and we are not going to let you start paying.

Is that a possibility under current practices by state utility regulatory commissions?

Mr. **Jennings**. Very much so.

Mr. **Paquette**. Very real.

Mr. **Jennings**. Very much so.

Mr. **McCormick**. I would disagree with that.

I have seen——

Senator **McClure**. Well, why would you say they do not have the authority? Are you saying they do not have the authority to do that? Or they just have the good sense not to do that?

Mr. **McCormick**. Well, it could be a little of each, but——

— Mr. **Paquette**. I think Mr. McCormick himself is having——

Senator **McClure**. Could be, but are you relying on that?

Are everyone of you at this table conscious of the dichotomy that comes when state utility commissions grant you the authority to build a plant—you have applied, you have got the authority, you go ahead and build the plant and then when you are ready to put it on line they say we do not think that was a prudent decision, you eat it?

Mr. **McCormick**. Yes, that is happening a lot.

Senator **McClure**. That is happening?

Mr. **Paquette**. And even without getting into second-guessing contracts—and Mr. McCormick's company itself is in a legal battle with the Michigan commission right now—I do not think it has been cleared up—it was not when I was there a year and a half ago—regarding the purchase of oil from——

Senator **McClure**. Is not the problem that we have here that particular aspect of the regulatory process rather than competition?

Mr. **Elston**. I think that this new format of doing business really changes the name of the game there. The fact of the matter is that the utility regulator right now does not—under this new system does not simply say yes, you can build.

When I put a contract before them, I guarantee a price that I will build that for, and if I do not build it, I eat it.

And that is very different from saying yes, you can build and we will pay anything. And that is the old system.

So, you have got a very different system now that the independents and the IPPs are bringing to the situation, and I think it dramatically will change the regulatory scene as well.

Senator **McClure**. Let me ask this question in this way. If to this legislation was added the provision that the state regulatory commissions have full authority to regulate the contracts as NARUC has requested, would you still support the legislation?

Mr. **Elston**. I think the legislation as it stands provides for that because the states have full prudency review and what this, I think, will force, which I think is helpful, is that that prudency review will take place at the time the contract is executed, not after the fact.

Senator **McClure**. Well, that is what you hope, but that has not been the fact so far.

Mr. **Elston**. But the prices have never been guaranteed so far. Now, you have guaranteed prices that they can respond to.

Senator **McClure**. But if the NARUC provision is added that gives the states the regulatory authority over the contracts, including prudency review, including wholesale rate review, would you support this legislation under that circumstances?

Mr. **McCormick**. No, I would not support it because——

Senator **McClure**. Mr. Willrich?

Mr. **Willrick**. I would not, but, Senator, it will not work that way in terms of——

Senator **McClure**. Well, it is not working now that way either. Mr. Elston.

Mr. Elston. My read of the situation is that they—under Senator Johnston's bill have full right to prudency review of those contracts. So, I think that it is unnecessary language in the bill.

Senator McClure. And wholesale rates?

Mr. Elston. I think that is clearly FERC's jurisdiction right now.

Senator McClure. And control over multi-state holding companies?

Mr. Elston. No, I do not think. I mean, obviously——

Senator McClure. Would you support it if they had that authority?

Mr. Elston. Well, I do not think you can give to a regulated—to a regulatory agency in one state authority over a multi-state utility.

Senator McClure. Well, that is a good theoretical question, but it had nothing to do with the question I asked.

Mr. McCormick. Well, Senator, I think the answer to your question is—and I have seen the list that NARUC has put together—and basically they are reaching for authority that they do not currently have in state and federal law.

Senator McClure. I understand that. No doubt the current kind of market that you are suggesting, we create.

Mr. McCormick. Well, I guess it is my belief and the belief of many, including Ashley Brown, who is a state commissioner who just wrote an article in Public Utilities fortnightly that they essentially have most of the authority that they need under this.

The Chairman. Would the Senator yield at that point.

Senator McClure. Sure. There are some who surely feel that and there are some who feel they do not.

The Chairman. Just to make a point, I think the Senator from Idaho understands that this bill does not preempt so that whatever power the state now has or wishes to exercise under state law, they can do so.

Senator McClure. I understand that, but as Senator Ford said, we ain't through with this bill yet. And I am trying to find out what because I think the answer is somewhat revealing, and I understand the frustration you have with the utility process that in many, many instances forces utilities to take all of the risk and the utility agency that has the responsibility for regulation takes none of it. I do not think that is the way that it should work at all. I would like to correct that as well if we could get that done, but I am somewhat hesitant to get into the field of preemption of state regulatory authority.

I am a little bit concerned that if I get the thrust of the support, not just what I hear here today, but what I have heard in all of the lobbying I have gotten from all the sides on this, that really this is sought by some as a way to circumvent state regulatory commissions, and that bothers me.

I also know that, Mr. Willrich, you and your companies and other companies in California have been fighting the question of transmission access, and I suspect that becomes heightened competition—heightened demand upon us in legislation is to deal with that question of transmission access.

I do not think this bill is going to go through to the end without addressing that question. I do not know how it will be answered in this process in this body or in the other body. But I think you have to be prepared, be willing under your own scenario to accept whatever may happen with regard to expanded state regulatory authority or expanded authority over transmission access.

It simply is not going to work in my view to create IPPs and then say well, you will just have to struggle to get on those lines. I do not think it is going to happen that way.

Senator McClure. My time has expired, Mr. Chairman. I will wait for the second round, thank you.

The Chairman. All right, Senator Ford.

Senator Ford. Mr. Chairman, I interrupted a while ago, and so I will not take any time.

I might say to the three proponents of the legislation suck it up, but this bill is not going to stay like it is, and I believe that is a known fact. So, even though you are here today, it is typical.

That is the reason I do not try to cosponsor many pieces of legislation. It never turns out the way you intend it to turn out.

So, I look forward to your interest in this piece of legislation as changes are made. Thank you, Mr. Chairman.

The Chairman. Thank you, Senator Ford.

Senator Burns.

Senator Burns. Thank you, Mr. Chairman. This is the first time that I have been involved in a hearing of this type with the power companies. I will probably have some questions, and I would like permission of everybody here because I have learned quite a lot this morning—if I could address those questions in writing to you and if you would respond, if that is all right with you? Then I will have some for them later on.

Thank you, Mr. Chairman.

The Chairman. Thank you very much, Senator Burns.

Senator Wirth.

Senator Wirth. Thank you very much, Mr. Chairman.

Mr. Chairman, as I sit and listen to this, I am having a feeling of very intense deja vu. 15 years ago we started discussions about the telephone company, and when we would have regulatory hearings in the Commerce Committee on the House side on telephone rates, there would be two or three witnesses here, a couple of members of the trade press, two or three people in the hearing room, a couple of lost tourists, and that was about all.

In 1975 I introduced the Pro-Competition Resolution related to AT&T and the room, like today, it was jammed, and you could barely hear the witnesses from the sound of all the lobbyists' clocks ticking out in the audience. The parallel is intense.

I remember as well asking Mr. DeButz when he came up—he was the Chairman of AT&T—when he came up and told us how terrible competition was, if he would introduce all the people in the room that were related to AT&T. We started over on one side of the hearing room and about seven minutes later we had gotten to the first aisle. So, I just asked him if he would please have everybody related to AT&T stand up, and the whole room stood up.

I am not going to do that today, Mr. Chairman, but I would cite that only as a parallel.

We were also told at that point, Mr. Chairman, that competition was going to be absolutely devastating to the system, that it was going to provide all kinds of technical harm to the system. We had gotten to the point where things were so regulated with AT&T that when a company tried to bring in new covers for a phone book that was disallowed because AT&T said it would cause technical harm to the system.

We heard today about lack of redundancy in equipment undercapitalized companies, fear of default and so on, and I am reminded of exactly the same issue.

We were told at that point as well, Mr. Chairman, that rural consumers were going to be deeply damaged and there were two examples that were used. There was a small phone system, 14 lines in the bottom of the Grand Canyon, and there was another, the little old lady in Sequim in Al Swift's district, who was going to be harmed. And I see a lot of people out there nodding. You all were listening to that. That rural telephone service was going to be absolutely devastated.

Well, it did not happen, and that kind of argument that we heard again today.

Consumer and shareholder issues, no rate protection, utilities build an alliance with the consumer groups to try to threaten them that rates were going to skyrocket if there were any kind of competition. Well, that did not happen either.

I was struck also by your testimony, Mr. Paquette, and yours, Mr. Brooks, when we used to hear from the AT&T people they would always start out by saying you know, I started in this business 40 years ago climbing poles, and you all cited justifiably your long experience in the industry, the implication being, of course, that anybody who has not had that long experience in the industry, does not have a right to get involved in this industry.

I am not suggesting that that is precisely what you were saying, but certainly that was a lot of what we have heard.

Finally, we were told over and over and over again the same arguments that we heard today, that vertical integration is essential for the consumer, for the economy, for the international competitive system, and the system is the solution we heard from AT&T, that vertical integration is probably absolutely essential for the cure for lower back pain as well.

The only argument we have not heard was the argument that was brought in by AT&T at the last moment and that was that if we had competition, it would incredibly harm our defense capability and that competition and the Soviets would come across the inner German border the minute competition was allowed. [Laughter.]

Now, to compete the parallel, Mr. Chairman, I can only say if the parallel is valid—and I have just been absolutely struck by this—the question that we face is was competition a good thing in the telephone industry? And I have come to the conclusion that absolutely there is some debate about that, but I have come to the conclusion that absolutely it was, Mr. Chairman. [Laughter.]

What we did was to bring in an extraordinary amount of technology. It was very good for the consumer in pricing for the consumer, provided access that we never had before, opened up a whole lot of new marketplaces, and difficult as it was, the status quo was no longer valid.

Competition, as pointed out, is already here. We have in 33 states, I understand, competitive entities and that is happening in the telecommunications world as well. The genie is out of the bottle, and we cannot put it back in again. The genie was out of the bottle in the telecommunications world, and it was a good thing. We had—a whole lot of new alternatives were developed, and that was a very sound and appropriate approach for us to be taking.

From my perspective, Mr. Chairman, the age is over when efficient economics are going to be defined by the regulator. Let us give Ronald Reagan his due. The marketplace is a much better and a much more efficient mechanism for regulating our economy than a public utilities commission.

Now, there are a number of fundamental issues in this legislation. There are some very fundamental issues here, and having made that statement about where as a general approach I am coming from and the parallels here, I think we ought to—think you have done a great job in getting this out there. I know that the wrath of Achilles has descended upon you for many quarters. That is perfectly all right. It is a familiar position to be in.

But there are a lot of very important issues that are here that I have not heard really addressed much this morning. First, the issue of a decentralization of decision making. You know, do we, if we follow this approach, are you we encouraging a kind of decentralization of decision making in the power in the public utility business, and is that the direction that we want to take? Are we inexorably following that course, and does that conflict with the kind of regionalism that you were asking about a little bit earlier?

Are there transmission access problems? Are there technical problems in the area of transmission access? I think that that is a legitimate concern.

I think we have to ask the utilities, how are you going to meet the power supply needs if we do not do this? Will you start to build other utilities, other power plants?

The three of you I understand from your testimony all have excess supply. What would happen if we had other people here who do not? Are, in fact, you going to go out and build power plants?

There are some very legitimate concerns that are faced in this, Mr. Chairman, and you know I would like just to begin with, if I might—and I will close with this—just ask any of you who might like to comment on the decentralization issue. Are we moving down a decentralization line irrevocably, if we were to pass the Chairman's legislation, and is that a good thing?

Mr. PAQUETTE. Could I comment, Senator?

Senator WIRTH. Please, Mr. Paquette.

Mr. PAQUETTE. I think we are, and I think that is the issue that we talked somewhat about earlier, that if this bill is passed it just pushes us further down the road for the others to make the decisions that the utilities have made as to what kind of capacity and when and how big and what kind of quality it will be.

Senator WIRTH. Then the question is, what is wrong with that? I mean, what is wrong with having a variety of voices in that area?

Mr. PAQUETTE. I think what is wrong with it is that we the utility, the investor who has the responsibility of supplying the customer, we will lose control on the fundamental part of where do we get our production?

Now, you alluded to the fact that the telephone industry has been broken up. I do not think that is really a good parallel, because what the telephone companies have become are separate operating company instead of a national organization. We are already hundreds and hundreds of separate operating companies in the United States.

If the telephone industry fails to produce, you get a busy signal. If we fail to produce the lights go out. So it is a tremendously different kind of a problem when you are talking about the electric utility industry.

We have been responsible, and we have met that responsibility for over 100 years of keeping the lights on better than any nation in the world. I think if we go down this road, we are only increasing the chance that the lights will not stay on.

Mr. McCormick. Senator Wirth.

Senator Wirth. That is a very interesting parallel that Mr. Paquette draws. Who would respond to that—the busy signal versus the light going out?

Mr. McCormick. Well, let me say, in the gas industry which I mentioned before, which is an essential service, the natural gas industry, we have a separate distribution, transmission and generation sector.

In effect what we are suggesting here is not even to disintegrate transmission and distribution but mainly just the generation sector, and I would say with respect to the decision-making, Senator, while the supply of electricity might be decentralized, I think under this bill the decision-making would still be centralized in the hands of the utility, because the utility is the one that will be writing the specifications on the contract.

This reliability and operability issue that has been brought up so much today, we are about to bring on line, we are a partner in the largest cogeneration plant in the United States, 1,370 megawatts, and it is a PURPA project.

There are seven owners in it and the contract between our utility and that PURPA cogenerator is a very tight contract. It allows the utility to dispatch the plant. It has specifications on reliability, design and so forth, and I can tell you that that plant is as reliable and is designed as well as any plant in the United States.

The utility itself has the power to do that through the contracting mechanism, and if it does not do that, then it is its own fault, so I would say in that sense the decision-making authority is not being decentralized.

Mr. Paquette. I would not put up the gas industry and say, an example of reliability of supply. We have a gas business at Philadelphia Electric, and we all lived through the 1970s when the producers abrogated contracts. We could not take on additional customers for a period of about six to eight years and that is an example of what happens when you separate the production from the distribution. I do not think we want to head that way in the electric business.

Mr. Elston. But I do not think that that is the issue that we are looking at here. The fact of the matter is that under this bill the utilities are squarely in the decision-making position. They can decide to build, because it would be more reliable, or they can decide to buy because it will be more reliable. They will be in the decision-making position.

If you listen to the testimony carefully by all three of these witnesses that are against this bill, they essentially start with the hypothesis that they will sign a crummy contract with me, and I have yet to have a utility do that. They suggest that somehow they will sign a contract that allows me to shift all the risk to them, and then I will go out to the financial markets and raise money with it.

Well, that is just a lot of baloney. No utility has done that. No responsible utility would do that, and all of their arguments about shifting risks and advantages to the independents are based on the hypothesis that they make bad decisions.

This bill that is on the table today—and I think Senator Ford asked the question, would we support a mandatory bill? I do not know of anyone that would support a mandatory bill here. That would be bad for everybody. That is the antithesis of competition, which is what we are talking about here.

This is not a mandatory bill. It creates the option for responsible utility executives to make smart, good decisions and to give them other options when they are making those decisions.

Mr. BROOKS. Senator, I would have to say that this is not a hypothesis that we were worried about these contracts. Houston Lighting and Power has some very excellent contracts with their QFs.

We have not had any earthquakes in Texas lately, thank goodness, but we do have hurricanes, and when Hurricane Gilbert came down the path it was 700 miles away, a clear, shiny day, two days before anything could get there, and Houston Lighting & Power was given notice of intent by all of their major QFs that they intended to terminate service when the hurricane got there.

As a matter of fact, one QF serving Texas-New Mexico Power with 396 megawatts did terminate service and Houston Lighting & Power had to pick it up. Those are the kinds of problems we are talking about.

The CHAIRMAN. Why would QFs terminate in a hurricane?

Mr. ELSTON. They in fact did not terminate, Senator. They were required contractually to notify the utility and they did what they were required under the utility contract to do, the possibility that they might have to terminate because of the hurricane.

In fact, a careful examination of the record there shows that their performance was excellent and in some cases provided excess power over and above their contractual requirements in order to meet some shortcomings of the utility system. The facts just are absolutely contrary in terms of the reliability in the performance of the independents in that hurricane situation.

Mr. BROOKS. The facts are not contrary. They performed fine because the hurricane never arrived. [Laughter.]

Senator FORD. Mr. Chairman, I want to recapture my time. I want to talk about airline deregulation. [Laughter.]

Senator WIRTH. Mr. Chairman, I thank you very much and I know that this is a major shift and a change, and I think you are to be commended for putting out on the table this set of ideas, which really makes people think very differently about competition versus regulation, about economics and economic forces, about alternative approaches, about what is going on long-term in terms of where the decision-making is.

There are some very serious questions here that I think we have begun to address, and I look forward to continuing testimony and work on this. I thank you all very much for being here. I think it has been a fascinating morning. Thank you, Mr. Chairman.

The **Chairman**. Thank you. Let us let Senator Murkowski recapture his time here.

Senator **Murkowski**. Thank you. I will be very brief, Mr. Chairman. First of all I want to thank you for resurrecting ANWR. [Laughter.]

For those that are rather puzzled——

Senator **Wirth**. I would like to strike my previous statement from the record. [Laughter.]

Senator **Murkowski**. This is the amendment to the authorization for competitive oil and gas leasing in the coastal plain of the Arctic National Wildlife Refuge, Mr. Chairman, and I will be thankful I mentioned something to my staff and the response was something—well, the Chairman was looking for an empty shell that was hanging around, so I am glad that we still have a shell.

Mr. Chairman, this is very interesting and obviously the extension of interpretations here can go into such things as wheeling—and I can sense as a businessman the realization that we have got two values here. One is an orderly process that those in the established utility would like to see maintained, and the realization that what you are proposing here is a reexamination, opening up, let the free market work.

Theoretically it ought to benefit the consumer. It does not necessarily in all cases create more competition, reduce rates. But I am wondering if this question, Mr. Chairman, would be appropriate to set.

In my mind at least, from the point of view of protecting the traditional market of the established utility from allowing a potential growth coming, that it has to make a decision on whether it wants to meet or allow an opportunity, if this legislation were passed, for somebody to go into the power business in that traditional marketing area of the utility, and whether the utility would feel forced to precommit, or have an overabundance of capacity to ensure that any market evaluation in that area resulted in a determination that indeed the established utility was meeting the market and therefore there is no place for the private supplier that wants to go into the business, and therefore keep them out by that methodology.

I recognize there are transmission concerns and all kinds of other limitations, but I am wondering if each side could just address that one question, and that would be the extent of my contribution, Mr. Chairman.

Mr. **Jennings**. I would be happy to try to respond to that. I do not think you could find evidence today, nor would you in the near foreseeable future of utilities who might build or acquire capacity as a strategy to foreclose the need for new capacity that might be supplied by IPPs.

The likelihood—the regulatory environment, for example, that is described by Bill McCormick really precludes that effectively. That will differ in matters of degree across the country, but that might be a very unwise strategy for any company to do.

Those that may have capacity in excess of even their reserve requirements today I can assure you ended up in that situation perhaps because load growth tapered off against long-range planning and construction scenarios for major plants, but not to foreclose the IPP entrants into the business.

Mr. WILLRICH. It is nice to have an area where we can agree. I think that utilities are not in the business of building excess capacity. When that occurs, it is a result of misforecasting in a highly uncertain environment what future loads are going to be.

The issue before the committee is, in terms of when additional capacity is deemed to be needed, do we want to have that capacity competitively procured or not? This legislation would simply create that option. It would not create a mandate that states, or the country have to go that way, but rather very intelligently create the option.

Mr. MCCORMICK. In fact, each individual state is going to have the determination. Its state commission is going to decide whether it wants to have its utilities more competitive or not, and that is beginning to happen already.

Senator MURKOWSKI. Thank you, Mr. Chairman.

The CHAIRMAN. Thank you, Senator Murkowski. Senator Conrad.

Senator CONRAD. Thank you, Mr. Chairman.

I am struck as I listen this morning about potential deregulation at least in part of this industry, that the last industry where we allowed partial deregulation was the S&L industry.

It was not a particularly happy outcome, and I am wondering if those who are here this morning could just comment and share with the rest of us what the risks are of proceeding along this path.

That is, we saw when we had partial deregulation in the S&L industry that people moved to do things that were high risk and the results were devastating. What is there to convince us that we are not going to have the same kind of problem if we allow partial deregulation here?

Mr. ELSTON. I think the key difference is that we are not talking about any government guarantees here, and that was the basic and fundamental problem in the S&L industry and this is just a completely different world for that reason.

Once again, I think the most important thing in looking at this legislation is to realize that we are only creating—here are no government guarantees. We are simply creating options that can be put before utility executives for them to choose if, in their best judgment, they think it is the best thing for the ratepayer.

The CHAIRMAN. If the senator would yield, there is no deregulation here of anything. Whatever regulation there is maintained, either by FERC in the case of wholesale power, or by PUCs in the case of the local distribution company.

Senator CONRAD. Well, do we not have, though, in fact a situation in which the IPPs are out from under PUHCA and to some extent that constitutes a deregulation?

The **Chairman**. Well, PUHCA prevents the IPPs—it does not regulate the IPPs, it just, in virtually every situation it simply prevents them from being there.

Mr. **McCormick**. The IPPs would still be regulated by the FERC with respect to rate issues, transmission issues and related matters.

Senator **Conrad**. Mr. Jennings.

Mr. **Jennings**. The amendment—those IPPs, senator, are not prevented right now by that 10 percent limitation. They are discouraged by it because they can submit to regulation by the SEC under the Holding Company Act now if they exceed that.

The **Chairman**. Is it not true that for practical purposes they are prevented? Whether they should be or not is another question, but are they not, practically?

Mr. **Elston**. I can attest to the fact, because I have been trying to raise money now and doing it successfully for the last ten years for these independent power plants, that if there is any suggestion to a financial institution that you would get swept in under the Holding Company Act—out the door immediately. So to suggest that it is a technical problem I think is not to deal with reality here.

Mr. **Jennings**. Well, let us talk about practicality. Let us first address the issue, the breadth of the brush with which our adversaries paint this morning.

Do not be misled by statements about the dearth of capacity or the imminent shortages of capacity of the industry or the United States at large. Study the data that is available from the electric reliability councils represented by the North American Electric Reliability Council.

There are not capacity shortages faced in my part of the country or in those in which my brethren are located. There may be 17 companies who have a particular problem.

There are certainly some entrepreneurs who would like to take advantage of opportunities that may become available in the generation marketplace, but please do not paint my system, or the part of the country I am from, with that broad a brush.

We have adequate supplies now. They are not excessive by anyone's definition, and I have plans in place as a company, and every confidence of the ability to implement those plans to continue to serve our own electric loads, and I suspect there are 36 other utilities that are identified in our remarks that can likewise make that contention.

We are not creating competition here and it is not real competition. Competitive bidding does not translate into true economic competition within the generation sector. The content of my testimony with respect to the capital cost advantages, one reason for that—and practically speaking, practically speaking, I spent 13 years trying rate cases for my company in two state retail commissions, and I can assure you that if the alternative is there, mandatory or not, you do not have to amend this statute to have a practical effect of its mandatory implementation in the states.

Because of the capital cost advantage alone, projects will be demonstrated on paper to be cheaper today and the cheaper option is that that will appeal to my regulator, and I speak from 13 years of trial counsel experience in that respect.

At least in my area of the country, the implication is that we have freedom of choice and I can assure you that we will not have freedom of choice. It will be politically inappropriate for the regulators to do anything other than to compel me to take advantage of this.

Senator CONRAD. Mr. Brooks.

Mr. BROOKS. Mr. Conrad, let me respond to your question about the partial deregulation. We understand that there is no attempt to deregulate, but we think what it really results in is a partial deregulation because——

Senator CONRAD. That is really the thrust of my question.

Mr. BROOKS. Yes.

Senator CONRAD. Do you not open up a situation——

Mr. JENNINGS. Absolutely.

Mr. BROOKS. Yes, we think we do, because we will have a third party in here that is not regulated and the only regulation that occurs from that is an after-the-fact regulation about prudence of a contract itself in future years, and we do think it is a deregulation to a certain degree.

Senator CONRAD. What are the implications of that from your perspective?

Mr. BROOKS. Of course, and I outlined some of those, I think today. We are worried not only about the operation of that but we are worried about the prudence reviews by the commissions down the road.

We have discussed this before, but we will be the ones that will have to have the prudence reviews down the road, not the EWG, because they will have a firm contract on a certain price and if later on we find out that it is not a good deal for our customers, we will be the ones that will be left holding the bag.

Mr. ELSTON. Again, the hypothesis is that they signed a bad contract and that the regulators are going to force them into signing contracts that are bad for the ratepayer. That is a hypothesis, the basic hypothesis of the argument against creating this option.

Mr. MCCORMICK. Well, if you want to protect yourself from that regulatory risk, the thing you do is first sign a good contract, as Paul said, and then you take it to the commission for approval and let them approve it or disapprove it.

Mr. BROOKS. It is easy enough to do that, and say that they are bad contracts. I am not talking about bad contracts. I am talking about contracts judged on the facts today. If you judge these contracts ten years down the road and the facts have changed, then retroactive rate-making is what I am talking about.

It applies the same day to us. We have all lived through this and we have reiterated this today time and time again. We have the same problem with these contracts that we have on prudence reviews of the facilities we have constructed.

Mr. ELSTON. But again, I made the point there is a difference here. Under the old system you went in and said, could I build a plant, and you estimated the cost and there were cost overruns and they came back and said, that cost a lot more than you said it was going to cost.

Here, when I come in with a contract, if I do not deliver at that price, I eat it. It is not the utility that eats it.

Mr. **Brooks**. That is well and good, except that this current day commission cannot guarantee that future commissions will agree with those things and they may decide that that price that looked so good three years ago is not good today and therefore we will only allow portion of it.

Mr. **Willrich**. Senator Conrad, I do not want to leave you with the impression from listening to this discussion that what we are talking about here is an either-or situation.

The point here is that what we are creating is a supply option, and I look forward to—my vision of the future includes both a healthy component of generation that is built within traditional electric utility lines and a healthy component of independent power that is built pursuant to competitive procurement by electric utilities and you put the two together and you will wind up with a low-cost, reliable electric supply system for the country.

So it is not a question—I think we tend to think of this in terms of an either-or situation. It really is a both-and, as far as the future of the country is concerned.

Senator **Conrad**. Let me ask you this. Let me ask you as a follow-up this simple question. If we pass this as it is drafted and as it is before us, what is to prevent an IPP from cruising into an area where it is already served by another utility and creaming the market—going after a big user, taking that out and leaving the utility with a reduced base and as a result increased rates for the small businesses and the local consumers?

Mr. **Willrich**. Because sales under the proposed act are to electric utilities only. There is not a provision for what is called retail wheeling, and I am opposed to retail wheeling.

Mr. **Paquette**. I think we all agree with that position.

Mr. **Jennings**. Same answer, though. Same answer, because if you were to come in as an IPP and offer to build and make it public to my commission and my customers, that you are willing to build 300 megawatts at an installed cost of $100 a KW and then just make it available to me, you put me in a heck of a box, you know, because you could displace some higher cost generation that I have got on line right now, and it will be stranded.

Mr. **McCormick**. Well, first of all a utility, if it does not need capacity it does not have to go out for bids and does not have to solicit any power, and I really do not believe the argument, or have a hard time following the argument that if an IPP comes into an area where a utility has all the capacity it needs, first of all it is going to take the risk of building a facility that it might not sell a megawatt from.

Then secondly, I have a hard time believing that the Public Service Commission, and whether it can legally do it, will attempt to force a utility to abandon existing capacity in favor of building an entirely new plant that is not needed. That really has to stretch the imagination.

Mr. **Paquette**. I think it is a very real possibility. It would not be a question of abandoning. It would just be a question of not utilizing some equipment that currently is operating.

Mr. **Elston**. But it is just not sensible to say that—I mean, you can always dream up crazy ideas, but why would a utility regulator tell a utility to choose a more expensive option going forward than the cheaper option. That does not make sense.

The problem here is that the right analysis, which every utility executive that I know and every regulator that I know would look at, is a going forward analysis. What is the cost of operating the plant, the more expensive capital plant that has already been built, versus the cost of building and operating the new plant?

If it turns out that it is cheaper to build and operate, then it is the sensible thing to do, but no one is sitting around saying that some regulator, and I hope no utility executive, would choose the more expensive option.

Once again, the problems here are only problems to the extent, given the options that are put before the utility executives and the regulators, that they make bad choices.

Senator CONRAD. Let me, Mr. Chairman, just commend you for opening up this subject, because I really think it is a public service.

I think we have got some very important issues here and I for one think this does open up the question of transmission policy in this country, and I think it opens it up in a very serious way. I wish we had time to go into that more this morning, but I think it is going to be a natural follow-on.

The CHAIRMAN. Well, these questions are before us whether we look into them or not. That is why I think we need to look more deeply into them.

Senator Bumpers.

Senator BUMPERS. Mr. Chairman, I am a novitiate on this issue. I am not an expert on PUHCA. I am one from a state who got it stuck in him about as deeply as you can get it by FERC, and so I have a very healthy suspicion of anything that FERC is going to do.

And so I go to the basic part of the bill, which troubles me the most, and that is, it seems to me that what we have here is a situation where, I would say, probably all of these IPPs are going to be selling power at wholesale, and therefore FERC is going to have total jurisdiction over all of these sales. Is that correct, Mr. Elston?

Mr. ELSTON. I think FERC will have the jurisdiction, but ultimately the states are left with the prudency review authority to determine that——

Senator BUMPERS. I am familiar with the Pike County decision and prudency rule and so on, but that is not very satisfying to me. Is it your position that that would be sufficient?

Mr. ELSTON. Not by itself. I think that what you have got to look at here is the concept of a competitive system, where a utility goes out and says they need to build 300 megawatts of capacity. We have found that for every one megawatt they want to buy, they have had proposed to them 12 megawatts. And they, then, make a decision as to which of those proposals they want to buy.

Then, typically, this is the way it works, they then take it to their State regulators, and their State regulators approve those power sales contracts. And I am literally talking about what my experience is in a number of different States. And it is only at that point that a contract that has won that competition with a 12-to-1 ratio, where the utility itself has chosen to buy it, and where the State regulators have approved it, at that stage of the game it gets to FERC. And FERC asks the question: Is it a just and reasonable rate?

The **Chairman**. If the Senator would yield.

Under this legislation, the States retain their regulation of the buyer.

Senator **Bumpers**. Retain their jurisdiction over what?

The **Chairman**. Of the buyer of the electricity which, in this case, would be your local company. And FERC would acquire the—well, FERC now has the jurisdiction over wholesale sales. We simply create new entities which could make wholesale sales.

Senator **Bumpers**. Mr. Chairman, is not virtually every sale by an IPP to an investor-owned utility, or anybody else for that matter, is not that going to be a wholesale sale?

The **Chairman**. Exactly. And that is going to be regulated as to the seller by FERC.

Senator **Bumpers**. But only insofar as prudency is concerned, is it not?

The **Chairman**. No, they would set the price with respect to the seller.

Senator **Bumpers**. The local PUC would?

The **Chairman**. But the PUC retains jurisdiction over the buyer, which means prudency, which means they can say yea or nay, and effectively they could set the price by saying we are not going to approve your buying any.

Senator **Bumpers**. But it seems like you are heading into a train wreck here between FERC and the local people because FERC has specifically ruled that States may not regulate purchases made pursuant to a FERC allocation order. That is what we got into in the Grand Gulf case. We were allocated a share of the cost of that plant and they specifically said that the States may not review that, and the Supreme Court upheld that in I guess it was 1986.

Mr. **Willrich**. That was a particular case where a multi-State holding company was involved——

Senator **Bumpers**. It was an integrated holding company.

Mr. **Willrich**. That is right. And what we are talking about here is a situation where a utility that is subject to State regulation goes out for bids for additional capacity and, in the first instance, the bidding approach is evolved by both the local utility and the State Commission behind it. So that in that situation, a parallel to the Grand Gulf situation would not arise.

Senator **Bumpers**. Well, let me ask you this. Is it your feeling that under this bill, and it is a fairly complex bill, I am quite sure Senator Johnston is the only one that fully understands it. [Laughter.]

And I worry about that. [Laughter.]

Let us walk through a hypothetical case where the local utility, which is a part of an integrated holding company, wants to buy power from a proposed IPP. At that stage, would the Arkansas Public Service Commission have any control over the price they are proposing to pay for the power?

Mr. **Willrich**. They could.

Senator **Bumpers**. I do not want to know whether they could or not, I want to know——

Mr. **Elston**. Well, let me—perhaps I could state it this way.

Mr. WILLRICH. They would have to assert their authority. If they wanted to do it, yes they could. They have the authority.

Mr. ELSTON. I could tell you that if the local public service commission has not approved that contract, I cannot finance it. The reality is that without that approval of the local jurisdiction, there is no plant that is ever going to be built. It is just not going to happen.

Mr. McCORMICK. Furthermore, the local public service commission has so many ways, through the regulation of that utility, to convince it and to persuade it not to enter into a contract that it does not like, that it can make its way felt in many, many ways.

Senator BUMPERS. See, that is what we thought. [Laughter.]

And we got awarded 36 percent of a $4 billion plant, even though we had been told categorically that we would not be required to take any power from that plant if we did not want to. And then FERC takes jurisdiction of it because we were not buying a part of the plant, we were buying power. It was a wholesale power sale; FERC took jurisdiction and said if they lied to you about it, that is their business. You have no right to do anything except take 36 percent of the power of this plant.

Now, that has been mitigated some, and I just say— —

The CHAIRMAN. And that is really a different question, Dale.

Senator BUMPERS. I think it is a slightly different question, but it is the one that makes me gun shy. And I am not picking on them because I think Middle South really has made a monumental effort to redress that on behalf of the people of our State, and I applaud them for their efforts.

But I can just tell you that when you answer me and you say that, for example, if AP&L or Middle South wants to get into a consortium with somebody to build an IPP, and I can tell you that is the reason NARUC is violently opposed to this bill, because they just feel that train coming; they think they are going to be deprived of the right to protect the people of Arkansas.

We have a law on the books in Arkansas, I think, Mr. Willrich, you testified before I got here, so a staffer told me, that you are now precluded from building or participating in power within your service areas, is that right?

Mr. WILLRICH. We have a competitive bidding scheme, Senator Bumpers, in California, where, if the utility is the low-cost provider, the utility builds the plant. Now that is on the utility side.

We also have an independent generating company. And, in terms of participating with the independent generating company in our State, those rules remain to be seen as to how they will evolve, but so far, affiliated companies are not prevented from serving their own utility.

And in our case, we are staying outside of our service territory in Southern California Edison's case. Mission Energy provides a considerable amount of power to SCE Corp.

Senator BUMPERS. Well, I was about to say a moment ago that in our State, we have a law that simply says that the utility companies will provide power to the people of our State at the lowest possible cost.

Mr. WILLRICH. Right.

Senator Bumpers. And I assume that most states have a similar provision. And my point is simply this. How can we enforce that law if we have no jurisdiction on the front end on whether that power ought to be bought or not?

Now, I understand the right of determination of prudency, but I understood you a moment ago, when I said, Would they be required to go to the local regulatory agency and ask for permission to get involved in, number one, this IPP; and number two, determine whether or not you could fix a rate right then that they could approve or disapprove?

Mr. Willrich. And my answer—I hope it still is consistent with what I said earlier—it is consistent—is that if the state commission in Arkansas will exercise its authority, if it has that legal authority—I am not familiar with the exact authority and limitations in the State of Arkansas——

Senator Bumpers. Well, we got it usurped, you see, because it was a wholesale sale.

Mr. Willrich. But if you adopt competitive bidding rules within Arkansas for additional capacity, the State of Arkansas could, I believe, review the bidding process and review the results of that process, front end, for additional capacity.

Senator Bumpers. Well, let me just say, Mr. Chairman, and I was late getting here, and I see that you and I are the only two left, and I do not want to delay the hearing, but I want to say there is a certain siren song in Senator Johnston's proposal: Everybody loves competition.

And if I thought for a minute that the ratepayers of my state could be protected, and not only protected, but actually gain from this through the kinds of competition that he envisions in this bill, and you know, I see no reason why there should not be some competition in this business, but it is just sort of like Lucy holding the ball for Charlie Brown every fall. I have been fooled before around here. [Laughter.]

And I do not think this bill is going anywhere right away, but I certainly intend to do everything, if we go to mark-up on this any time, I am going to try certainly to nail down every one of these concerns that I mentioned, plus many more.

The Chairman. I say to my friend from Arkansas, that there have got to be an awful lot of questions asked and answered before we go to mark-up. That does not mean that we deliberately delay the bill, but this process, as you can see, is going to take some time. So you do not need to prepare for a mark-up tomorrow.

Senator Bumpers. One further question, Mr. Chairman, that I wanted to ask Mr. Elston. This is called "Independent Energy Producers: The New Electric Generating Sector," you are familiar with that, are you not?

Mr. Elston. Yes, sir.

Senator Bumpers. There is a statement here on page 15 that says "On Market Power, Not Just an Insider's Game."

> Major input suppliers could use sufficient market power over their products to influence the outcome of the competitive process depending on the market conditions for supplies.
>
> Four situations in particular demand close attention. One, self-dealing: Electric utility affiliates acting within their service territory raise market power concerns

because of the complete dominance that their parent utilities have over the process of acquiring new generating capacity.

Would you comment on that?

Mr. ELSTON. Yes. I think that report in your hand was issued by the National Independent Energy Producers, an organization that I am Vice Chairman of, and it is made up of companies like my own, which are small, independent companies that do not own transmission or have distribution franchises.

And I think one of our concerns, which is not really the subject of today's hearing, but I guess will be the focus, really, of the next hearing, is that as we go forward to try to increase the competition here and create this option, that we do it in a way that is careful and thoughtful and recognizes the market power of the entities that are out there, and provides adequate protections against the abuse of that market power.

So, from our point of view, it is absolutely the right move to make to create this option. And it simply has to be done in a way that, then, recognizes the realities of market power of entities out there, such as a utility that has the exclusive right to sell electricity and probably exclusively owns the transmission lines.

There is no question that that kind of an entity has market power in its own territory.

And it seems to me that it is incumbent upon the Congress to be satisfied that there is adequate regulatory authority to protect against the abuse of that power.

And I think, frankly, that my associates to the right, both of whom are from utilities—and that no one really argues with the principle there. We may disagree on the character of the existing authority and the need for additional authority and the specifics of it, but I do not think that there is anyone that disagrees that that is not a legitimate question that has to be looked at carefully here and that the Congress has to be satisfied that there is adequate protections.

Senator BUMPERS. Well, let me just walk through a case with you, if I may.

Let us take an integrated holding company that is operating in three or four states. And let us assume there are five subsidiaries within that integrated holding company. Let us assume further that the integrated holding company is proposing to own a third, with some other integrated holding company owning a third, and a third integrated holding company owning a third.

So you have got three companies, we will say, covering 10 states, and maybe 20 subsidiaries, local power distribution companies. And they are proposing to build a substantial generating plant. And each one of them is going to own a third of it.

How are we going to decide—let me make this a little more interesting. Let us just take one holding company, who goes to General Electric and says, how about you, you know, you are always looking for a good deal, why do not you put up 60 percent of money or 50 percent of the money, and we will put up 50 percent? We are going to have to have some additional generating capacity. We have got to have more power. Let us, you and I, build this billion-dollar facility.

General Electric says fine, it looks like a pretty good deal to us.

And you are making your plans for this.

And let us assume that somebody else comes to you and said look, we do not want partners, but we would like to generate power, and we can generate the same amount of power you are going to get out of this plant for 10 percent less money than you are getting ready to invest in it.

Now, how is that dispute going to be resolved?

Mr. ELSTON. Well, I believe that—I mean, let us say I am the second party, and I can produce the——

Senator BUMPERS. Now, you and I both know what ought to happen if we are talking about true competition here.

Mr. ELSTON. Well, that is right. And I think that—I will make sure, myself, that if I think I have the better plant and I am not being fairly treated by that utility, my first stop will be my local regulators.

And I do not believe the local regulators will stand for that.

My second stop will be——

Senator BUMPERS. But there again you are assuming that at that stage the local regulators have a right to step in.

Mr. ELSTON. Well, I am just saying, that is my first stop. My second stop is at the FERC, because the FERC—ultimately, that contract has to come to FERC and has to be viewed as just and reasonable under the law by FERC.

And it will be my opportunity at that time to make the case and to put forward the evidence to FERC that this was unfair competition; that the reason that the utility made the deal with this entity that it partially owns is because it is a sweetheart deal for the unregulated portion of it and that it treated me unfairly, and therefore, it is not a just and reasonable rate.

And at that point FERC should reject it, as long as I carry, successfully, the burden of proof in that situation.

You should understand, and I think the report suggests, that we want to make sure, as part of this process, that there is no ambiguity about that question that FERC has the authority to turn around and say no in that situation, and to send them back to square one, number one.

Secondly, we think that there should be a review by Congress of the type of remedies that FERC can act on at that particular moment.

I have now probably spent a half a million dollars making the case to FERC in order to document the fact that they have abused their market power in this insider deal. And it has taken me two years probably, frankly, to do it, and we think that you should have remedies available to FERC that will be so draconian that they will not do it in the first place.

So it is just a simple principle of a good enforcement strategy.

And finally, and perhaps we think in this particular case, where you are talking about a utility subsidiary doing business with its parent, we think that this situation is particularly troublesome and lends itself to potentials for abuse of market power, cross subsidies, inside deals, and the rest of it, and that the Congress should perhaps look at a preemptive move here by ruling it out in this particular situation.

So, from our point of view, we think that that is, inherently—let me state it this way.

How can you convince me that I am going to get fair treatment if I go in to compete for a utility's business and I am competing with a subsidiary of that utility? I mean that is a hard case, I think, to make for me and for me to be convinced.

And so our encouragement here is to do everything possible to make sure that those abuses cannot take place.

Senator BUMPERS. Mr. Elston, just to be absolutely fair about it, right now there is no competition. The local utility company goes into the PSC and they say we need more generating capacity and here is what we are proposing to do; they are going to build either a coal-fired plant or a gas-fired plant, or something else. And here is what we think it is going to cost, and here is what we will probably ask for in the way of a rate increase in order to build it.

Now there is no competition now. Is that a fair statement?

Mr. ELSTON. Well, I think that that would have been fair five years ago, but I, in fact, do not think it is the case today.

I suggest to you that there is not a utility regulator or a utility executive that does not first have to answer the question: Can I get a better deal for the ratepayer by buying this, as opposed to building it myself?

And I can absolutely assure you that in New York, in Virginia, in the states that I operate in, that those questions are being asked. They are being asked in a very sophisticated way, they are being asked with the right kind of economic comparisons taking place—not perfectly.

There is a lot of shaking out that has to happen in this assessment process, but I am convinced that we will work hard on it and the regulators will, and we will have a fair assessment system when we are done.

Mr. PAQUETTE. Senator, could I comment on that last point? Because I think there is a lot of competition in the utility, even without IPPs and even without competitive bidding, there is competition, first of all, from the review of the utility operations by the PUCs.

Because of our inherently monopolistic position, the PUC was established to maintain balance between competition on the one hand, and the need to have a monopoly to avoid duplication.

But, beyond that, there has always been and it continues more today, this competition from one utility system to another in attracting new business. And every utility has a marketing and an area development department that is trying to attract businesses into its territory and also to enable other businesses in the territory to expand.

So, we have competition and we are all very interested in keeping our rates as low as possible not only to attract business, but to make the whole environment that our customers live in the best possible.

So, there is competition.

Senator BUMPERS. You also have to make a profit. I mean, you have stockholders.

Mr. PAQUETTE. Yes, sir.

Senator BUMPERS. And you have to make a profit for them. So, the PUCs are really the arbiters, are they not? I mean they are the umpires.

Mr. PAQUETTE. They are the arbiters between the need to have efficient rates on the one hand, reliable supply, and a fair return to the investors.

Senator BUMPERS. Well, Mr. Chairman, I could ask 40 more questions on this. It is interesting, it is one of the most fascinating things we have had in this committee, and I, too, want to applaud you for throwing it out for our consideration. And I will do my best to become more knowledgeable and try to make a wise decision at the proper time.

The CHAIRMAN. Thank you, Senator Bumpers.

Mr. Jennings, you put your finger on what is a recurrent theme of the opponents here, and that is you said that the regulators will compel people in your position to take advantage of this. Did I understand that correctly?

Mr. JENNINGS. Yes, Mr. Chairman, that is correct.

The CHAIRMAN. And Mr. Brooks, I do not know whether you said it today or whether you have told me otherwise about the fact that you think there might be displacement of existing capacity.

Is this at the heart of it? What I am trying to get at is what is at the heart of those of you who are in areas that have—I think you said, Mr. Brooks, Central Southwest has eight years of supply, no problems, you do not need any new things right now—so, since this bill is entirely voluntary, what is it that you are afraid of from the standpoint of your company? I mean, when you talk about reliability and all those things, you do not want it, you do not have to take it.

Mr. BROOKS. Let me answer that by going back to what Mr. Willrich said first, "If it ain't broke, don't fix it."

And we have heard how many thousands of megawatts have been installed already and we think that can be installed, and we are not one to stand up and say we would never be interested in EWG or IPP power, because we most certainly would when the time comes for us to build additional construction.

But we do not want it mandated to us that we have to do that. We do not want it mandated that we have to provide transmission, and we do not want our public utilities commission thinking that that is the only way to go, that is, to consider the cheapest price. And if you have 23,000 megawatts that are bid to you, you are going to have many, many opportunities for a very cheap price, and it is going to be hard for our commissions to pass up.

So we are worried about the reliability aspect of it, but we are not saying that it is not a player. But we do not think we need this bill, because it works fine just like it is today.

The CHAIRMAN. But the bill does not require you to take it?

Mr. BROOKS. No, sir. That is what we think is—I understand it does not require us to take it, but it is the first step. And there are always nay-sayers that say this is the first step; we are worried about what is to come.

The CHAIRMAN. Are you talking about the next step in legislation or that they would use this bill?

Mr. Jennings.

Mr. **Jennings**. Yes.

Drawing upon the experience I had as an attorney looking at the legislative history behind the National Energy Acts, and particularly PURPA, the legislative history that surrounds this issue that is being created right now that provides for and encourages competition. Competition is like apple pie and motherhood, how can you be against it?

The real question is whether this, your bill, sir, without revision, whether it really creates that. We move from a cost-of-service basis for regulating and establishing utility rates in the country to a market-based rate, if the competition really arises.

Well, I can assure you that if the market-based prices are below cost, then the business fails. So it is either going to be at or above cost if you move into the truly competitive environment.

You do not create that here. You know, it is not so much what the utility industry or—let me not generalize, it is about what my company and those that serve in my part of the country need. We do not need additional options right now.

I think the entrepreneurs who would like to gain entry into the unregulated segment of the generation business with an unregulated rate of return, without the accountability to the retail regulator, like I have and will always have, they are the ones that need the options. I do not need options right now. I have got options galore.

The **Chairman**. Well, I understand that. The question is, though, others want the option, and we change the law for others, why is it that your company would object to having the option?

Mr. **Jennings**. Because, as a practical matter, I mentioned in general terms what my own plans for future power supply are. It is a combination of upgrading existing fossil equipment, perhaps life-extension projects, perhaps, from time to time, a relatively short lead time combustion turbine of my own, that I do not have to depend upon for tremendous energy requirements, but perhaps for certain peak load capacity requirements in the summer part of the season.

My commissions, from the experience I have had, will have evidence produced to them from people like Mr. Elston, from representatives of Elcon or from the individual members of Elcon who participate in my rate cases locally, General Motors Company, Ford Motor Company, Armco Steel, the Department of Energy.

They take the position that if a cheaper alternative, irrespective of how long it may be cheaper, or whether it in fact is least-cost, if a cheaper alternative is available, they accuse me and my commission of imprudence if we do not elect to take it, if we do not choose it.

And that is the concern I have is that those planning alternatives that I have now available—I am trying to advertise and encourage my own retail customers to replace, when it is time to, their old central air conditioning units with new units that are built in compliance with the new federal energy efficiency appliance standards. That is one of my options for conserving or perhaps taking care of some of my future megawatt need.

If my commission is presented evidence, in a hearing or not, that there is a cheaper alternative available, then they are going to make me show cause why it should not be chosen. And that cheaper alternative is a foregone mathematical conclusion. If the IPP is project-specific——

The CHAIRMAN. Well, two questions arise there. First of all, why are you so convinced that the PUC is going to mandate things that would give you lack of reliability, an unreliable fuel source, an unreliable financial structure, et cetera, et cetera? Is there a record that they have done that?

Mr. JENNINGS. I have to be a bit circumspect in that answer. [Laughter.]

Let me put it this way, I do not mean to be, and I really do not believe myself to be the cynic, but I did spend several years lawyering retail rate cases. I was a lawyer for 12 years. I have been with my company a relatively short time compared with these gentlemen, about 15 or 16 years, and I have seen the commissions in both the states of Kansas and Missouri completely turn over at least three to four times each in that relatively short career that I have.

By the nature of the job and, I think, by the nature of the regulatory process, it tends to be a little bit more shortsighted in nature. And we have to learn to adapt to and live with that.

I think it is one of the things you must recognize as a regulated utility that that is another one of the managerial challenges that you deal with. And I think we can deal with that. I would rather deal with the defects that perhaps have surfaced in the regulatory process in the country than to——

The CHAIRMAN. Well, let me ask you this. I hate to keep interrupting, but the time is so short.

Mr. JENNINGS. I am sorry. I am getting long-winded, I apologize.

The CHAIRMAN. What you are saying, in effect, is that while this bill would not permit the local PUC to require you to use an IPP, that the operation of this bill could effectively prevent you from putting into operation your own plans?

Mr. JENNINGS. As a practical matter, it will invite into my retail markets proposals made by Mason, whose company would like to market their new facilities in the Midwest as well as the West, I am sure, and by Paul, likewise, who would like to market in my area. And if there is a potential market there, they would love to present an alternative to my commission.

I do not fear that as competition.

The CHAIRMAN. Well, now, it seems to me that this—I asked a question very early on——

Mr. JENNINGS. Right.

The CHAIRMAN [continuing]. That it seems to me that this really enhances the power of the PUC or the regulator because he retains his power to set rates over what you build and to say yea, nay and have prudency over what you build, and he also has a rule for comparison; that is, what somebody else might build.

Why, then, should PUCs—are PUCs misadvised thinking we are taking something away from them? Are not PUCs really getting more power here?

Let me ask you, Mr. Elston.

Mr. ELSTON. I definitely think that that is the case, and I think the fact that you—I mean, it may be uncomfortable and Mr. Jennings might prefer to only put one option before the PUC, but I think it is a healthier and more in the public interest to have a variety of options put before them.

It puts them squarely in the driver's seat. They are able to look at those options, and I am confident, frankly, that they are not going to make short-term, shortsighted decisions.

I have found that in the areas where I participate that having outside companies like my own come in have forced more discipline into the analysis and gotten people to focus explicitly on the question of well, what are the long-term concerns here, what are the short-term concerns, what is the question of reliability—a whole series of questions that probably are dealt with much more explicitly and ultimately, as you say, when you put choices before the regulators at the local level, I think ultimately enhancing their authority in the situation.

Senator BUMPERS. Mr. Chairman, will you yield?

The CHAIRMAN. Yes, certainly.

Senator BUMPERS. Mr. Elston, on that point let me ask you this. Is there not a lot of—these gentlemen were saying there is a lot of competition right now, and the competition takes this form sometimes.

Arkansas Power & Light goes in and says we want to build this facility because we have got to have another 500 megawatts of power by 1994, blah, blah, blah. And ratepayers fight back or ratepayers united—every one of you have got these groups in your state—they come in and say they do not need this extra capacity. They are simply wanting to build more capacity, and it is going to cost us a lot more money, and they make a case that you do not need it. Number two, that if you do need it, there is a cheaper alternative than building that capacity. Number three, if you are not going to build it, you can buy it from somebody else cheaper.

So, number one, the PUC is going to decide between all of those things. Do you really need the power and if you do, is this the cheapest way to do it or can you buy it wholesale from someplace else in another state that has excess capacity, some other company, all of those things.

Then on the other side, the environmentalists come in. They say if there is anything we do not want, it is another fossil powered plant in this state. There is plenty of natural gas or something else, all the environmental reasons that you do not need this plant. All of those things really foment an awful lot of competition right now, do they not?

Mr. ELSTON. Well, I think that there is——

Senator BUMPERS. Not competition for the building of the plant, but other kinds of competition.

Mr. ELSTON. Well, yeah. Competing interests is what I would call them as opposed to competition for the best product, and I think that what you get when you have a company like mine and several companies like mine coming in and proposing, you get to look across that body of issues that you have referred to having to do with the need for supply and the cost and the environmental impact, and you look at them and the reliability, the fuel supply, and the system in general, and you look across all of that body of issues, and you have real options before you, and then you make some judgments about it.

And that, as opposed to, I think, the system that you have right now I would describe not so much—there is some elements of competition there, but I think they are relatively de minimis relative to what you have seen recently coming out with the independents in there, and what you end up doing is having from the regulator's point of view, they have got a utility before them that wants to do something. That is more information than you can imagine relative to anybody else—I mean, they are really the ones that know what is going on—and it is very hard really, I think, to penetrate all of those complete details and reach a solid judgment when you just have one player there.

But when you have more than one player there with options before the regulators, you get to compare, and I think you get a lot more intelligence on what you should do.

Senator BUMPERS. I have one last question. Mr. Elston or anybody on that side of the table, do you not have some latitude here? For example, if you are proposing to build or participate in the building of an IPP and you go to the public service commission, assuming that they have first shot at it, and you make your case for building this or participating in it, and somebody else comes in that is pretty big in the utility building business and they say to the commission, they may need the power, but I promise you the cost of the power they are proposing to generate is more than we would build it for.

And the public service commission said well, now, look. We have an obligation to force you to buy power from the cheapest source in order to protect our ratepayers. You do not say this publicly, but in the private board room you are literally saying if we are going to have to buy power from somebody else, we are not going to buy it.

I mean, do you not have tremendous monopolistic power over building your own as opposed to taking power from somebody else that could build that capacity cheaper?

Mr. ELSTON. Well, I think that that—since I am not a utility and do not have a franchise base, I think that that question should be addressed by people that run utilities because that is the issue.

Mr. WILLRICH. That was the old system that—well, we do not say it is broke, but that is the situation where a utility would decide to proceed on the theory that there was a monopoly out there in generation.

The point here is that you are quite right in suggesting that the way to test that is to have competitive bidding for additional capacity requirements of utilities.

And I think, Senator Bumpers, that your concern about future Grand Gulfs would be addressed not directly because Senator Johnston's bill would not change existing law, but in terms of how the system would work in the future, that indirectly that the State of Arkansas with the state utility could establish a competitive bidding scheme where that kind of problem would not arise in the future.

If it did in the sense of a FERC issue, again, that issue would be in a different framework today than when it was back in the days when the Grand Gulf facts were laid down. And actually, I think that there was not a full litigation of the situation at FERC that led to the Mississippi case in the first place—that if there had been full participation recognizing there is competition out there, it would have been a different outcome.

Senator **Bumpers**. Would you envision under this bill a procedure under which the utility that was going to need the power would simply advertise for bids?

Mr. **Willrich**. Yes. That is correct.

Mr. **McCormick**. And that is happening quite a bit right now, Senator, in a number of jurisdictions.

Mr. **Willrich**. More and more states are adopting those kinds of schemes.

The **Chairman**. We have got a vote on, and we are past the halfway point. Let me ask one final question because obviously we have got a lot more questions to ask for future hearings.

Is anybody prepared to say that PURPA on the whole is not a success? I do not want the reasons, just do any of you think it is not a success.

Mr. **Paquette**. I question very seriously the success of PURPA.

Mr. **Jennings**. As do I.

Mr. **Brooks**. I do, too.

The **Chairman**. I assume you all think it is wonderful.

Senator **Bumpers**. Well, I wish I had time to take the other side of that issue.

Mr. **McCormick**. I think PURPA has been a success.

The **Chairman**. Well, maybe we ought to——

Mr. **Paquette**. Not as far as the electric customers are concerned. I think electric customers' bills are probably higher today because of PURPA.

Senator **Bumpers**. But you are getting——

The **Chairman**. I think we ought to examine that on another day. [Laughter.]

Gentlemen, each one of you has done an excellent job. I really want to commend this panel. You have done very well, and I look forward to future hearings. Thank you very much.

[Whereupon, at 12:28 p.m., the hearing adjourned, subject to the call of the Chair.]

COMPETITIVE WHOLESALE ELECTRIC GENERATION ACT OF 1989

THURSDAY, NOVEMBER 16, 1989

U.S. SENATE,
COMMITTEE ON ENERGY AND NATURAL RESOURCES,
Washington, DC.

The committee met, pursuant to notice, at 9:42 a.m., in room SD-366, Dirksen Senate Office Building, Hon. J. Bennett Johnston, chairman, presiding.

OPENING STATEMENT OF HON. J. BENNETT JOHNSTON, U.S. SENATOR FROM LOUISIANA

The CHAIRMAN. Good morning. The liability factor of the United States Senate is only about 20 percent this morning. We don't operate well in this bad weather. [Laughter.]

Today the committee is holding its second hearing on the issue of whether the obstacles to independent power production contained in the Public Utility Holding Company Act should be removed. Last week we had an excellent set of witnesses who provided us with an in-depth debate on the merits of Amendment 267 to S. 406, the "Competitive Wholesale Electric Generation Act of 1989." I believe that the committee members who attended last week's hearing learned a great deal, and I hope to continue that learning process this morning.

As we continue examination of the bill, I think it is important that we not let the perfect be the enemy of the good. Under any scenario, the changes that Amendment 267 would bring about are incremental. It is unrealistic to expect any one piece of legislation to solve all the world's electric regulatory woes. It is proper to judge the Holding Company Act proposal on the basis of any problems that it would create. It is not fair to criticize the proposal based on imperfections in the status quo. I mention this point because as I listen to the bill's critics, I often have the sense that they are confusing the world as it exists with that which the bill does and does not do.

As I have emphasized in the past, I have not made up my mind on this bill or, indeed, whether it should be brought to markup or not. But I am determined that in any case that the process of inquiry shall be fair and intellectually honest.

A number of issues were brought out at last week's hearing, and I expect that we will hear more about them today.

For example does Holding Company Act legislation create the opportunity for abuse of transmission access? Or is this matter adequately policed by FERC under the separate provisions of the Federal Power Act?

Do states have adequate authority to oversee wholesale purchases by their native utilities? Or must this authority be clarified as part of legislation?

Can competition in wholesale power provide true efficiencies? Or is the ability of IPPs to compete dependent upon leveraged financing or negative effects on a purchaser's balance sheet? On this last point I note that committee staff has prepared a cash flow model which challenges the view that leveraging is imprudent and that it invariably conveys cost of capital advantages.

We have a diverse set of witnesses this morning. They represent a range of interests and organizations. We do not have the clear bifurcation we had last week between those who said yes and just said no. Today we have various variations on the theme of yes and no. I expect we have a few that clearly say no, or one or two at least. [Laughter.]

But in any event, it promises to be an interesting morning with excellent witnesses.

I thought we would go five minutes on a direct summary of testimony this morning, if that meets with the witnesses' approval. If you would like a few more minutes, you might tell me now and we can do that. I would like to structure this the way you want it. What do you think? Bill and Bill?

Mr. McCOLLAM. I can do it in five.

Mr. BERRY. Five and a half.

Mr. KEARNEY. Five would be fine.

The CHAIRMAN. All right. We will turn on the lights for five. The yellow light comes on I think in about four and the red light is about five. And if you talk beyond that, we have the chairs wired electrically. [Laughter.]

I think that Senator Bradley wanted to make an opening statement.

Senator BRADLEY. Mr. Chairman, I don't want to make an opening statement, but is it your intention to have the gentlemen make their presentations without any questions until they are finished?

The CHAIRMAN. Yes, then we will get questions from all.

Senator Murkowski?

Senator MURKOWSKI. Mr. Chairman, I just want to commend you for your continuance in the area of testing the waters of the free market in electrical power generation. It is dark and deep, and obviously you can get electrocuted. But more power to you. [Laughter.]

The CHAIRMAN. Thank you.

We will begin this morning with Bill McCollam, President of Edison Electric on behalf of EEI.

STATEMENT OF WILLIAM McCOLLAM, JR., PRESIDENT, EDISON ELECTRIC INSTITUTE

Mr. McCOLLAM. Good morning. Mr. Chairman and members of the committee, I am William McCollam, Jr., President of the EEI. I am here today in lieu of John Ellis, Chairman and CEO of Puget Sound Power and Light and the current chairman of EEI, who unfortunately because of other business commitments could not be here today to testify.

The members of EEI are strongly committed to maintaining a reliable and efficient power supply system, and I can say unequivocally that they will continue to meet our customers' needs. The reliability of our electric system remains the envy of the world, and we are committed to keeping it that way.

Further, I think it is clear that under any scenario non-utility generation will be used to some extent to meet future capacity requirements.

At issue is what changes, if any, should be made to the Public Utility Holding Company Act to accommodate independent power producers. The issues presented by PUHCA are complex and produce divergent viewpoints even within the electric utility industry itself, which I am sure is no secret based on last week's testimony. They are honest and strongly held differences of opinion over whether PUHCA should be amended and over what changes would result from the proposed legislation and whether the potential benefits of increased competition outweigh the potential costs. Therefore, at the present time, EEI does not advocate Holding Company Act legislative changes because of those differences.

But despite those differences there are many areas of strong agreement among EEI member companies regarding related areas that arise in this debate. And I would like to stress these areas of consensus which we believe are critical to assuring that electric consumers are provided with adequate, reliable and environmentally acceptable service at the lowest reasonable cost.

First, we feel that PUHCA changes should not in practice preclude a utility or its affiliates from participating in wholesale markets on an equal basis with other entities.

Second, an electric utility should retain its managerial discretion to decide whether it will build facilities for itself or purchase electricity from others.

And third, the provision of transmission services should remain voluntary.

Let me explain briefly why each of these provisions is important to electric utilities and their customers.

First, if PUHCA were amended to exempt non-utility generators while continuing to subject utility owned facilities to its provisions, regulated utilities would be put at a competitive disadvantage. It makes no sense to exclude the most experienced supplier from building to serve its own customers. For fair competition to occur, utilities must be able to establish non-utility wholesale power supply subsidiaries, to finance them on the same basis as others, and to purchase from them as a least-cost source of supply under competitive bidding or another procurement plan.

We believe provisions of the Federal Power Act and state law and regulation are sufficient to address self-dealing and cross subsidy issues. Further, we believe that state regulators have ample experience with both of these issues.

Second, so long as utilities have the state imposed obligation to serve all retail customers in their franchised areas and are answerable to state regulators for the quality of their service, utilities should retain the managerial discretion to determine how they are going to provide that service. Certainly it would be inequitable to continue to impose the obligation to serve and take from the utility the discretion it needs to ensure reliability and efficiency.

Third, the provision of transmission services should remain voluntary. We believe that the current system of voluntary transmission access has been effective in reducing the cost of power production while at the same time maintaining the reliability of the grid. In many cases mandatory transmission could jeopardize a utility system's reliability and/or impose additional costs on their native load customers.

Because of the complexity of transmission and the potential burdens on utilities and their customers, we strongly believe that transmission should not be considered as a part of PUHCA legislation.

Mr. Chairman, nearly every utility decision faces a potential prudence review as evidenced from the record, and that involves also prudence reviews with respect to building its own facilities and purchased power arrangements. To help satisfy a growing demand for electricity in the 1990s, we need to develop different approaches both with respect to building and purchasing.

One approach would be to substitute before-the-fact and ongoing prudence reviews for after-the-fact prudence reviews with suitable safeguards to protect consumer interests.

EEI has formed a task force of CEOs to work actively with representatives of the National Association of Regulatory Commissioners to discuss and seek solution to these major areas of concern.

In conclusion, as this committee contemplates changes to the current structure of this industry, we encourage you to recognize that what is best for consumers may vary from system to system and region to region depending on the supply and demand situations which are unique to each utility. We believe that regulated utilities with their unique obligation to serve their consumers in cooperation with regulators must retain full control over their system and maintain the managerial discretion to determine the appropriate way to serve their consumers. Great care should be taken to make certain that if changes to PUHCA are approved, they should produce greater, not fewer, power supply options for utilities.

Thank you.

[The prepared statement of Mr. McCollam follows:]

TESTIMONY OF
WILLIAM MCCOLLAM, JR.

BEFORE THE UNITED STATES SENATE
COMMITTEE ON ENERGY AND NATURAL RESOURCES
NOVEMBER 16, 1989

I. INTRODUCTION

GOOD MORNING MR. CHAIRMAN AND MEMBERS OF THE COMMITTEE. I AM WILLIAM MCCOLLAM, JR., PRESIDENT OF THE EDISON ELECTRIC INSTITUTE (EEI), THE ASSOCIATION OF THE NATION'S INVESTOR-OWNED ELECTRIC UTILITIES. MEMBER COMPANIES OF EEI GENERATE APPROXIMATELY 77 PERCENT OF THE POWER PRODUCED IN THIS COUNTRY AND SERVE APPROXIMATELY 73 PERCENT OF ALL ULTIMATE CUSTOMERS.

I AM HERE TODAY IN LIEU OF JOHN ELLIS, CHAIRMAN AND CEO OF PUGET SOUND POWER AND LIGHT COMPANY AND THE CURRENT CHAIRMAN OF EEI. MR. ELLIS WAS HERE TO LISTEN TO THE TESTIMONY AT YOUR HEARING LAST WEEK AND WANTED VERY MUCH TO BE HERE TODAY. WHILE PREVIOUS BUSINESS COMMITMENTS MADE THAT IMPOSSIBLE, MR. ELLIS HAS WORKED VERY CLOSELY WITH US IN PREPARING THIS TESTIMONY.

MR. CHAIRMAN, I APPRECIATE THE INTEREST THE COMMITTEE HAS SHOWN IN THE ELECTRIC POWER NEEDS OF OUR NATION AND YOUR EFFORTS TO ASSURE A RELIABLE AND ADEQUATE SUPPLY OF ELECTRICITY IN THE FUTURE.

THE MEMBERS OF EEI ARE STRONGLY COMMITTED TO MAINTAINING A RELIABLE AND EFFICIENT POWER SUPPLY SYSTEM. THEY ARE EVER MINDFUL

OF ITS IMPORTANCE TO OUR NATION'S WELL BEING AND NATIONAL SECURITY. THIS COMMITMENT HAS BEEN DEMONSTRATED MOST RECENTLY BY THE HERCULEAN EFFORTS TO RESTORE SERVICE TO CONSUMERS FOLLOWING HURRICANE HUGO AND THE SAN FRANCISCO EARTHQUAKE.

IN FACT, ONE OF THE MOST COMPELLING ATTRIBUTES OF THE CURRENT SYSTEM OF ELECTRIC SUPPLY IN THE UNITED STATES IS ITS HIGH DEGREE OF RELIABILITY. WHEN SOMEONE TURNS THE LIGHT SWITCH "ON," OVER 99.9 PERCENT OF THE TIME THE UTILITY SYSTEMS ARE ABLE TO PROVIDE THE POWER INSTANTANEOUSLY. PROVIDING RELIABILITY MEANS HAVING ALL SEGMENTS OF THE POWER SYSTEM -- GENERATION, TRANSMISSION, AND DISTRIBUTION -- WORKING TOGETHER TO KEEP SUPPLY AND DEMAND IN BALANCE AT ALL TIMES. IT ALSO REQUIRES CAREFUL MONITORING, MANAGEMENT, COORDINATION, AND CONTROL OF THE SYSTEM.

I CAN SAY UNEQUIVOCALLY THAT EEI'S MEMBER UTILITIES WILL CONTINUE TO MEET OUR CUSTOMERS' NEEDS. THE RELIABILITY OF OUR ELECTRIC SYSTEM REMAINS THE ENVY OF THE WORLD, AND WE ARE COMMITTED TO KEEPING IT THAT WAY.

FURTHER, I THINK IT IS CLEAR THAT, UNDER ANY SCENARIO, NON-UTILITY GENERATION WILL BE USED TO SOME EXTENT TO MEET FUTURE CAPACITY REQUIREMENTS. AT ISSUE IS WHAT CHANGES, IF ANY, SHOULD BE MADE TO THE PUBLIC UTILITY HOLDING COMPANY ACT (PUHCA) TO ACCOMMODATE INDEPENDENT POWER PRODUCERS.

LAST WEEK YOU HEARD TESTIMONY FROM WITNESSES ON BOTH SIDES OF THE QUESTION OF WHETHER OR NOT TO CHANGE THE PUBLIC UTILITY HOLDING COMPANY ACT TO FOSTER A NEW CLASS OF WHOLESALE POWER PRODUCERS, EXEMPT WHOLESALE GENERATORS (EWGS). THE ISSUES PRESENTED BY PUHCA ARE COMPLEX AND PRODUCE DIVERGENT VIEWPOINTS, EVEN WITHIN THE ELECTRIC UTILITY INDUSTRY ITSELF. THERE ARE HONEST AND STRONGLY HELD DIFFERENCES OF OPINION OVER WHAT CHANGES WOULD RESULT FROM THE PROPOSED LEGISLATION AND WHETHER THE POTENTIAL BENEFITS OF INCREASED COMPETITION OUTWEIGH THE POTENTIAL COSTS.

BUT, DESPITE THESE DIFFERENCES, THERE ARE AREAS OF STRONG AGREEMENT AMONG EEI MEMBER COMPANIES RELATIVE TO MANY OF THE ISSUES WHICH THIS DEBATE RAISES. I WANT TO STRESS THESE AREAS OF CONSENSUS, WHICH WE BELIEVE ARE CRITICAL TO ASSURING THAT ELECTRIC CONSUMERS ARE PROVIDED WITH ADEQUATE, RELIABLE, AND ENVIRONMENTALLY ACCEPTABLE SERVICE AT THE LOWEST REASONABLE COST:

- PUHCA CHANGES SHOULD NOT IN PRACTICE PRECLUDE A UTILITY OR ITS AFFILIATES FROM PARTICIPATING IN WHOLESALE MARKETS ON AN EQUAL BASIS WITH OTHER ENTITIES.

- AN ELECTRIC UTILITY SHOULD RETAIN ITS MANAGERIAL DISCRETION TO DECIDE WHETHER IT WILL BUILD FACILITIES FOR ITSELF OR PURCHASE ELECTRICITY FROM OTHERS.

- THE PROVISION OF TRANSMISSION SERVICES SHOULD REMAIN VOLUNTARY; SUCH SERVICES CAN BE FACILITATED THROUGH APPROPRIATE PRICING.

LET ME EXPLAIN WHY EACH OF THESE PROVISIONS IS IMPORTANT TO ELECTRIC UTILITIES AND THEIR CUSTOMERS.

II. FAIR TREATMENT OF ELECTRIC UTILITIES AND THEIR AFFILIATES

IF PUHCA WERE AMENDED TO EXEMPT NON-UTILITY GENERATORS WHILE CONTINUING TO SUBJECT UTILITY OWNED FACILITIES TO ITS PROVISIONS, REGULATED UTILITIES WOULD BE PUT AT A COMPETITIVE DISADVANTAGE. IT WOULD MAKE NO SENSE TO EXCLUDE THE MOST EXPERIENCED SUPPLIER FROM BUILDING TO SERVE ITS OWN CUSTOMERS. SUCH A RESULT WOULD ACTUALLY LIMIT COMPETITION AND REDUCE THE NUMBER OF POWER SUPPLY OPTIONS.

IT IS NOT ENOUGH SIMPLY TO LET A UTILITY COMPETE THROUGH A REGULATED PLANT, AND EXPECT IT TO COMPETE EFFECTIVELY WITH HIGHLY LEVERAGED, UNREGULATED WHOLESALE POWER PRODUCERS. FOR FAIR COMPETITION TO OCCUR, UTILITIES MUST BE ABLE TO ESTABLISH NON-UTILITY WHOLESALE POWER SUPPLY SUBSIDIARIES; TO FINANCE THEM ON THE SAME BASIS AS OTHERS; AND TO PURCHASE FROM THEM AS A LEAST-COST SOURCE OF SUPPLY UNDER COMPETITIVE BIDDING OR ANOTHER PROCUREMENT PLAN.

WE RECOGNIZE THAT SOME ARGUE THAT ESTABLISHMENT OF NON-UTILITY WHOLESALE POWER SUPPLY SUBSIDIARIES CREATES THE POTENTIAL FOR UTILITIES TO ENGAGE IN CROSS-SUBSIDIZATION AND SELF-DEALING. HOWEVER, WHETHER A UTILITY BUILDS FOR ITSELF, PURCHASES FROM NON-UTILITIES, OR PURCHASES FROM ITS OWN SUBSIDIARY, ALL SUCH TRANSACTIONS HAVE ALWAYS BEEN AND WILL CONTINUE TO BE SUBJECT TO REGULATORY SCRUTINY. IN FACT, SELF-DEALING HAS ALWAYS BEEN A REGULATORY ISSUE IN THE INDUSTRY, WITH RESPECT TO FUEL SUBSIDIARIES AND WITH RESPECT TO UTILITIES THAT HAVE SUBSIDIARIES WITH PURPA QF OWNERSHIP INTERESTS. ON THE CROSS SUBSIDY ISSUE, CLEARLY EVERY STATE COMMISSION CAN AND DOES REVIEW UTILITY RECORDS TO ENSURE THE APPROPRIATE ACCOUNTING OF COSTS. WE BELIEVE PROVISIONS OF THE FEDERAL POWER ACT AND STATE LAW AND REGULATION ARE SUFFICIENT TO ADDRESS SELF-DEALING AND CROSS SUBSIDY ISSUES. NO OTHER INDUSTRY COMES UNDER CLOSER SCRUTINY THAN THE ELECTRIC UTILITY INDUSTRY.

III. MANAGERIAL DISCRETION AND RESPONSIBILITY

SO LONG AS UTILITIES HAVE THE STATE-IMPOSED OBLIGATION TO SERVE ALL RETAIL CUSTOMERS IN THEIR FRANCHISED AREAS AND ARE ANSWERABLE TO STATE REGULATORS FOR THE QUALITY OF THEIR SERVICE, UTILITIES SHOULD RETAIN THE MANAGERIAL DISCRETION TO DETERMINE HOW THEY WILL PROVIDE THAT SERVICE. THIS PRINCIPLE IS FUNDAMENTAL TO THE PRESENT STRUCTURE OF THE U.S. ELECTRIC SYSTEM, WHICH CONTINUES TO SERVE CONSUMERS WELL -- A FACT THAT SHOULD NOT BE FORGOTTEN AS WE CONSIDER THE CHANGES CONTEMPLATED BY AMENDMENT 267 TO S. 406.

EEI MEMBERS AGREE THAT CONTROL OVER THE INTEGRATION OF THE GENERATION FUNCTION INTO THE ENTIRE SYSTEM IS CRITICAL TO RELIABILITY AND COST EFFECTIVENESS. IN ORDER TO ACHIEVE THAT INTEGRATION, A SINGLE ENTITY MUST CONTROL THE SYSTEM. THE DECISIONS WHICH MUST BE MADE TO INSURE RELIABILITY AND EFFICIENCY -- INCLUDING THE FUEL MIX, PLANT SITING, SCHEDULED MAINTENANCE, AND ECONOMIC DISPATCH -- MUST BE MADE BY THE ENTITY RESPONSIBLE FOR PROVIDING ELECTRICITY TO THE ULTIMATE CONSUMER. CERTAINLY IT WOULD BE INEQUITABLE TO CONTINUE TO IMPOSE THE OBLIGATION TO SERVE ON THE UTILITY AND TAKE FROM THE UTILITY THE DISCRETION IT NEEDS TO MEET THAT OBLIGATION. THE UTILITY, THEREFORE, NEEDS THE DISCRETION TO DECIDE HOW IT WILL PROVIDE THE SERVICE FOR WHICH IT IS ANSWERABLE TO ITS STATE REGULATORS.

UTILITY DISCRETION IS BALANCED BY THE EQUALLY BROAD DISCRETION STATE REGULATORS HAVE IN SETTING RETAIL RATES AND DETERMINING THE PRUDENCE OF MANAGERIAL DECISIONS. IT IS ALSO CLEAR THAT THIS ARRANGEMENT HAS WORKED WELL FOR CUSTOMERS WHO RECEIVE EXTRAORDINARILY RELIABLE SERVICE AT REASONABLE PRICES.

IV. THE PROVISION OF TRANSMISSION SERVICES SHOULD REMAIN VOLUNTARY

SOME ARGUE THAT ANY CHANGES TO PUHCA SHOULD INCLUDE PROVISIONS REQUIRING A UTILITY TO WHEEL POWER GENERATED BY OTHERS. WE BELIEVE THAT THE CURRENT VOLUNTARY SYSTEM OF TRANSMISSION ACCESS HAS BEEN EFFECTIVE IN REDUCING THE COST OF POWER PRODUCTION WHILE

MAINTAINING THE RELIABILITY OF THE GRID. WHERE UTILITIES CAN PROVIDE TRANSMISSION SERVICES TO OTHERS WITHOUT HARMING THEIR OWN NATIVE LOAD CUSTOMERS, THEY HAVE AND WILL CONTINUE TO PROVIDE SUCH SERVICES. HOWEVER, MANDATORY TRANSMISSION COULD JEOPARDIZE A UTILITY SYSTEM'S RELIABILITY AND/OR IMPOSE ADDITIONAL COSTS ON THEIR CUSTOMERS, I.E., RETAIL AND REQUIREMENTS CUSTOMERS THAT UTILITIES HAVE AN OBLIGATION TO SERVE.

IN ITS RECENT REPORT, "ELECTRIC POWER WHEELING AND DEALING: TECHNOLOGICAL CONSIDERATIONS FOR INCREASING COMPETITION," THE OFFICE OF TECHNOLOGY ASSESSMENT (OTA) POINTED OUT THAT THERE IS SUBSTANTIAL UNCERTAINTY OF THE COSTS AND BENEFITS RELATED TO INCREASED TRANSMISSION ACCESS TO FOSTER COMPETITIVE GENERATION. ALSO, THE EXPERIENCE WITH COMPETITIVE BIDDING SUGGESTS THAT MANDATORY WHEELING IS NOT NECESSARY FOR A COMPETITIVE GENERATION MARKET. UTILITIES THAT HAVE CONDUCTED COMPETITIVE PROCUREMENT HAVE RECEIVED BIDS FAR IN EXCESS OF THEIR NEEDS WITHOUT THE NEED TO MANDATE TRANSMISSION SERVICES.

ADDRESSING THE ISSUE OF TRANSMISSION SERVICES IS A COMPLEX SUBJECT. THERE ARE TECHNICAL CONCERNS FOR MAINTAINING RELIABILITY OF THE INTERCONNECTED SYSTEM, AND ECONOMIC CONCERNS TO INSURE THAT FRANCHISE AREA CUSTOMERS, WHO HAVE PAID FOR THE DEVELOPMENT OF THE TRANSMISSION SYSTEM, ARE NOT REQUIRED TO SUBSIDIZE THE USE OF THE SYSTEM BY THIRD PARTIES. BECAUSE OF THE COMPLEXITY OF THESE ISSUES AND THE POTENTIAL BURDENS ON UTILITIES AND THEIR CUSTOMERS, WE

BELIEVE THAT TRANSMISSION SHOULD NOT BE CONSIDERED AS A PART OF PUHCA LEGISLATION.

V. THE NEED FOR REGULATORY REFORM

AS YOU KNOW, UTILITIES' SUPPLY PLANS HAVE COME UNDER INCREASING REGULATORY SCRUTINY IN RECENT YEARS. NEARLY EVERY UTILITY DECISION FACES A POTENTIAL PRUDENCE REVIEW. UNFORTUNATELY, INTENSIFIED REGULATORY EFFORTS TO HOLD DOWN ELECTRIC RATES HAVE LEAD TO A SUBSTANTIAL WEAKENING, IF NOT A TOTAL BREAKDOWN, OF THE REGULATORY COMPACT IN MANY JURISDICTIONS. NUMEROUS FINDINGS BY STATE REGULATORS THAT DECISIONS BY SOME UTILITIES TO BUILD NEW GENERATION WERE IMPRUDENT, AND SUBSEQUENT REFUSALS TO ALLOW THOSE UTILITIES TO PUT THE FULL COST OF THOSE GENERATING UNITS INTO RATE BASE, HAVE CAUSED UTILITIES TO THINK LONG AND HARD BEFORE COMMITTING TO CONSTRUCTING MAJOR NEW GENERATING UNITS. IT IS ESSENTIAL TO UNDERSTAND THAT UTILITIES ALSO FACE REGULATORY UNCERTAINTIES ABOUT ENTERING INTO LONG-TERM CONTRACTS TO PURCHASE POWER SUPPLIED BY OTHERS. UTILITY DECISIONS TO CONTRACT FOR POWER ALSO ARE SUBJECT TO AFTER-THE-FACT PRUDENCE REVIEW, AND UTILITIES CAN BE PROHIBITED FROM RECOVERING CONTRACT COSTS IN RATES.

WHATEVER DIRECTION ELECTRICITY POLICY TAKES, THE SERVICES WE PROVIDE WILL CONTINUE TO BE THE SUBJECT OF REGULATION IN THE FUTURE. THAT WILL BE TRUE WHETHER WE BUILD A PLANT IN RATE BASE OR ENTER INTO LONG-TERM CONTRACTS TO PURCHASE POWER SUPPLIED BY

OTHERS. WHETHER CONGRESS APPROVES THE PENDING LEGISLATION OR NOT -- AND WHETHER NON-UTILITY SUPPLIERS PROLIFERATE OR NOT -- UTILITIES WILL CONTINUE TO FACE UNCERTAINTIES IN THE REGULATORY PROCESS.

TO HELP SATISFY A GROWING DEMAND FOR ELECTRICITY IN THE 1990S, WE NEED TO DEVELOP DIFFERENT APPROACHES THAN THE AFTER-THE-FACT REVIEWS THAT HAVE BEEN INCREASINGLY APPLIED IN RECENT YEARS. UTILITIES SHOULD BE ABLE TO PERFORM THEIR FUNCTIONS IN THE PUBLIC INTEREST, AND, MOST IMPORTANTLY, WITH SOME ASSURANCE THAT THE RULES UNDER WHICH THEY OPERATE WILL CONTINUE TO PREVAIL IN THE FUTURE. WE MUST WORK TO BRING A NEW SPIRIT OF COOPERATION BETWEEN THE UTILITY INDUSTRY AND THE REGULATORY COMMUNITY TO YIELD MORE CERTAINTY AND STABILITY IN THE REGULATORY PROCESS. THIS IS ESPECIALLY IMPORTANT CONCERNING RECOVERY OF PLANT AND PURCHASE POWER COSTS, AND RETURNS ON INVESTMENTS.

ONE APPROACH WOULD BE TO SUBSTITUTE BEFORE-THE-FACT FOR AFTER-THE-FACT PRUDENCE REVIEWS, WITH SUITABLE SAFEGUARDS TO PROTECT CONSUMER INTERESTS. THIS WOULD BE ACHIEVED THROUGH CONTINUOUS REVIEWS, ASSUMING AGREEMENT HAS BEEN REACHED AS TO THE NEED, TYPE, COST, AND RATE IMPLICATIONS OF MAJOR NEW PROJECTS IN ADVANCE OF MAJOR FINANCIAL COMMITMENTS. THEREAFTER, PROJECTS WOULD BE SUBJECT TO TIMELY, PERIODIC, PROSPECTIVE REVIEWS AT PRE-DETERMINED TIMES RATHER THAN A MASSIVE REVIEW AT SOME UNCERTAIN FUTURE. UNDER SUCH A REGULATORY PROGRAM, IT IS POSSIBLE TO ACHIEVE A MORE EQUITABLE BALANCING OF RISKS TO ELECTRIC CONSUMERS AND UTILITY SHAREHOLDERS, AND THERE IS GREATER ASSURANCE OF AN ADEQUATE, RELIABLE, AND ENVIRONMENTALLY ACCEPTABLE SERVICE AT THE LOWEST REASONABLE COST.

I SHOULD ADD THAT EEI HAS FORMED A TASK FORCE OF CEO'S TO WORK ACTIVELY WITH REPRESENTATIVES OF THE NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS (NARUC) TO DISCUSS AND SEEK SOLUTIONS TO MAJOR AREAS OF CONCERN.

VI. CONCLUSIONS

THIS INDUSTRY WELCOMES THE OPPORTUNITY TO PARTICIPATE IN THESE IMPORTANT PROCEEDINGS ON MATTERS OF SIGNIFICANT IMPORTANCE TO THE FUTURE OF ELECTRICITY SUPPLY. AGAIN, WE WOULD LIKE TO UNDERSCORE OUR STRONG COMMITMENT TO PROVIDING ADEQUATE, RELIABLE, AND ENVIRONMENTALLY ACCEPTABLE SERVICE AT THE LOWEST REASONABLE COST. WITH OR WITHOUT CHANGES IN PUHCA, WE WILL MEET THAT OBLIGATION USING ALL THE OPTIONS AVAILABLE.

WE RECOGNIZE THE COMPLEXITY OF THE ONGOING DEBATE ABOUT THE FUTURE ROLE OF COMPETITION. EEI'S MEMBERS HAVE FACED INCREASING COMPETITION FROM NON-UTILITY POWER PRODUCERS, OTHER FUEL SOURCES, NEIGHBORING UTILITIES, AND EVEN FROM THEIR CONSUMERS FOR DECADES. COMPETITION IS A FACT OF LIFE IN THE UTILITY INDUSTRY.

AS THIS COMMITTEE CONTEMPLATES CHANGES TO THE CURRENT STRUCTURE OF THIS INDUSTRY, WE ENCOURAGE YOU TO RECOGNIZE THAT WHAT

IS BEST FOR CONSUMERS WILL VARY FROM SYSTEM TO SYSTEM AND REGION TO REGION, DEPENDING ON THE SUPPLY AND DEMAND SITUATIONS THEY EACH CONFRONT. THAT IS WHY IT IS IMPORTANT NOT TO IMPOSE ANY SINGLE VISION OF THE FUTURE ON UTILITIES AND, IN TURN, THEIR CONSUMERS. WE BELIEVE THAT REGULATED UTILITIES, WITH THEIR UNIQUE OBLIGATION TO SERVE THEIR CONSUMERS, IN COOPERATION WITH REGULATORS, MUST RETAIN FULL CONTROL OVER THEIR SYSTEM AND MAINTAIN THE MANAGERIAL DISCRETION TO DETERMINE THE APPROPRIATE WAY TO SERVE CONSUMERS. GREAT CARE SHOULD BE TAKEN TO MAKE CERTAIN THAT IF CHANGES TO PUHCA ARE APPROVED, THEY SHOULD PRODUCE GREATER, NOT FEWER, POWER SUPPLY OPTIONS FOR UTILITIES.

WE LOOK FORWARD TO WORKING WITH THIS COMMITTEE.

The **Chairman**. Thank you very much, Mr. McCollam.

Next we will hear from Sherwood Smith, Jr., who is Chairman and President of Carolina Power & Light from Raleigh, North Carolina.

STATEMENT OF SHERWOOD H. SMITH, JR., CHAIRMAN AND PRESIDENT, CAROLINA POWER & LIGHT CO., ON BEHALF OF THE ELECTRIC RELIABILITY COALITION

Mr. **Smith**. Thank you very much, Mr. Chairman. And as stated, I am Sherwood Smith. I am Chairman and President of Carolina Power & Light Company. I am also here representing a group known as The Electric Reliability Coalition.

The coalition is a group of about 80—excuse me—38—think in time we will be 80 because our membership is growing—utilities who have expressed their concerns, as is known I believe to the Chairman, in opposition to Senate Bill 406. Our concerns relate to our deeply held conviction that the enactment of Senate Bill 406 would do more than what has been described as perhaps being a simple removal of an impediment to further operations under the Holding Company Act.

We think the bill would have far-ranging consequences. We think that many of those consequences would be adverse to our systems and to our shareholders. We think it is likely that the burdens placed upon our systems for higher costs and perhaps degradated reliability are substantial risks, and for those reasons we would suggest to the committee that it not proceed to pass out and send to the Senate 406.

But we agree wholeheartedly with the Chairman that the discussions here have been very useful we think and instructive and insightful. As I said, we appreciate the opportunity to be here.

Carolina Power & Light Company is either a large middle sized company or a small big company. We serve in both the Carolinas. We serve about 930,000 customers. Our primary sources of fuel are coal and nuclear power. We use only a small amount of oil and natural gas and have only a small amount of hydroelectric power.

We are very much integrated with seven or eight large neighboring systems, and over the last 20 years we, as have most of the electric utilities in the country, have had to go through a very large expansion program. We think we have done that quite successfully, and we have been able to do that despite the challenges that have occurred under the regulatory system. Those challenges are well-known to this committee. But they involve higher costs, environmental legislation, problems with the siting, construction and costs of nuclear power.

But most of those challenges are behind us. We have even undergone what has been called a prudence review after the fact, and we would support wholeheartedly Mr. McCollam's statement that the value of a prudence review is before the fact and not after the fact.

With regard to the concerns that we have about Senate Bill 406, I think it is important that one realize that this legislation, once it would be enacted, we believe would have far-ranging consequences. We think that it would lead to the displacement of the regulated utilities, built, constructed, owned and operated generation to a large extent. To precisely what extent, obviously no one can tell.

The proponents of the legislation have said, well, doesn't this simply give the utilities another option. If we believe that it were truly a voluntary option, then obviously we would not be here speaking in opposition to the bill. We believe very firmly, based upon our experience dealing under a myriad of different state regulatory structures, that the state commissions would be faced with tremendous incentives to approve independent power entrepreneurs and generators whose short-term costs might appear to be lower than the regulated utilities' costs which we plan over time over the expected life of the facility, and that those pressures under the state commission operation would lead to the regulated utilities being forced to enter into arrangements with new non-regulated independent power producers which would do two things.

Those power producers would have the opportunity to raise capital at lower cost than can the electric utilities simply because they would be almost entirely leveraged, and they would be able to leverage themselves because they would have the contract with the utility probably approved by a commission. And those contracts might either be take or pay, or take and pay, or they would be front end loaded, as many of our PURPA contracts are today where large capacity costs are paid by the utility up front.

The higher costs that the utility would incur would be passed on to its ratepayers. And this would not occur overnight. This would occur gradually over a period of time. But as our costs of capital rise because of the large amount of IPP generation for which we are contracted to buy and support, that would raise our costs to our customers.

There were concerns expressed last week about reliability, and I won't go into the question of reliability any further unless there are questions because it was discussed with respect to I think a hurricane in Texas and there were people on both sides of that issue.

The concern that one would have about reliability is that the owners of the non-utility generating source would have the control over whether that source operated or did not operate. I would assume that they would seek to operate in good faith and that they would try to keep their units on line. But from the utility operator standpoint, you are in a quite different situation whether you own and control all the generation served in your system or whether a substantial part of it may not be under your ownership and control and may only be subject to contractual rights.

I think that there are great differences between the regulated electric utility industry and the gas and telephone industry, and I go into those in my comments. And I would welcome any questions. But there are very substantial differences.

I think that before enacting legislation, one must think about wheeling, whether or not legislation of this type would tend to create a world in which mandatory transmission access and wheeling did come about. There would be serious questions of wholesale bypass as well as retail bypass with consequent higher cost passed on to other customers remaining on the utility system, as well as stranded investment made by the utility.

The proponents of the legislation themselves last week and this week acknowledged that wheeling is an important companion to the proposal now before the committee although it is not advocated by all of the proponents of Senate Bill 406 that wheeling be included, but I think all of them recognize that it is an inevitable fact of life that we would all have to deal with. We think we would be seriously adversely affected.

I notice that the red light is lit. I apologize for taking a couple of minutes longer than perhaps my allotted five minutes. I certainly welcome any questions.

[The prepared statement of Mr. Smith follows; additional material appears in appendix II.]

November 16, 1989

Before the Senate Committee
On Energy and Natural Resources

Statement of Sherwood H. Smith, Jr.
Chairman/President
Carolina Power & Light Company

In Behalf of
The Electric Reliability Coalition

My name is Sherwood H. Smith, Jr., Chairman and President of Carolina Power & Light Company. I am appearing today not only in behalf of Carolina Power & Light Company, but also the Electric Reliability Coalition. The Coalition is a recently formed group that currently includes some 38 regulated investor-owned utilities. ERC member companies include 19 of the 50 largest investor owned utilities, which together produce well over 30 percent of all power sold by investor-owned utilities. The Coalition opposes enactment of S. 406 because we believe that it would impose unnecessary risks upon the reliability and costs of service to our electric consumers and would tend to impair the ability of the regulated utility industry to perform its mission of public service.

Written testimony of the ERC is being submitted for the record. Also being submitted is an economic study prepared for ERC analyzing, among other things, the artificial cost-of-capital advantage that Exempt Wholesale Generators (EWGs) likely would enjoy by virtue of their highly leveraged financing and EWGs' ability to shift financing and certain operating risks and costs to their utility customers. I ask that these documents be made a part of the record.

My experience at Carolina Power & Light Company has covered about 25 years. I have seen many challenges to our industry and changes in it. I have had the privilege of serving on a number of industry boards, including the North American Electric Reliability Council, the Southeastern Reliability Council, of which I am chairman, and as a director and past chairman of the Edison Electric Institute. I was a principal witness and industry coordinator during the lengthy hearings on the Public Utility Regulatory Policy Act (PURPA) in 1977 and 1978. This experience has enabled me fully to appreciate utility economics and the complex coordination that underlies America's highly reliable electric system, and to be concerned about the potential adverse impacts of this bill on electric utilities' ability to meet their obligations of public service.

Carolina Power & Light Company is an investor-owned electric utility servicing over 930,000 customers in a 30,000-square-mile service territory in North and South Carolina. Our system has a generating capacity of about 9,700 megawatts. We use coal and nuclear energy as our principal sources of fuel, operating 19 coal-fired generating units and four nuclear units, as well as about 40 smaller hydro-electric, combustion turbine, and waste heat units.

Our company serves a dynamic and attractive service territory. Our business investment and economic growth for many years have been outpacing the national average. We have been challenged over the past two decades to raise enormous amounts of capital to build efficient generating, transmission and distribution facilities to meet the economic growth of our region. Yet, we believe we have passed all the tests of providing adequate, reliable and reasonably priced electric service "with flying colors." We are well-prepared in our planning for the future.

Carolina Power & Light's excellent performance is not unique. The investor-owned electric utility industry has done an outstanding job over many, many years in meeting the needs of electric consumers in this country by providing them with an adequate, reliable and reasonably priced source of electricity. This has been accomplished by a large and incredibly complex system of vertically integrated utilities with generation, transmission and distribution facilities interconnected throughout the country at strategic locations for reliability and economical transactions. Our consumers and our entire economy have benefited enormously from this fully integrated and regulated system of generation, transmission and distribution.

Our company and the other ERC companies are fully committed to meeting future demand. Future demand will be met in a variety of ways by (1) utilities building new generation; (2) efficiency, conservation and load-management; (3) inter-company purchases of electricity; and (4) utility purchase arrangements with co-generation and other sources when it is in the long-run interests of customers to do so. In the long run, it is my deep conviction that the best interests of our electric customers will be served by a strong, viable, and regulated electric utility industry which operates under a framework that encourages an adequate and substantial amount of generating capacity to be built, owned and operated by regulated public utilities.

We have adequate generating capacity in the country today. Some have expressed concerns about the future. If the shortfalls of generating capactity should begin to emerge in coming years, they will be limited to a few utilities in localized situations, and will reflect specific state regulatory actions. Where there are problems, they are State related and can be corrected at the State level. There is certainly no national capacity crisis that would justify basic changes in the existing system of regulated electric utility service.

By way of reference for the discussions before this Committee concerning the growth in electric demand, I would like to cite the recent report of NERC entitled "The Future of Bulk Electric System Reliability in North America, 1989-1998" (referred to as the "1989 Reliability Assessment") and the comparison document, "The 1989 Electric Supply and Demand" report.

Proponents of S. 406 say that it would "foster competition" as an option in the generating segment of the electric industry. This, however, is an oversimplification of a very complex issue. First, one should recall that many years ago it was determined from experience that regulation should be a substitute for traditional competition in this very important industry, in order to assure adequate service and to prevent the uneconomic and wasteful duplication of facilities. Second, the "competition" that this Bill would now promote would not be competition between equal sources of supply, or public obligation, and the adverse impact upon regulated utilities and their customers could be severe.

It is generally believed that EWGs would be project-financed with 90 percent or more debt, supported by long-term take-or-pay power contracts with purchasing utilities. The utilities, by contrast, are and will continue to be constrained by the financial markets and by regulation to debt-equity ratios of around 50-50. By virtue of these uniquely high debt-equity ratios, which are not seen over the long term in any other industry, EWGs could have a cost-of-capital advantage over traditional utilities or utility owned EWGs of 20 to 30 percent, translating into a very significant pricing advantage over the cost to the utility of financing comparable generating capacity. EWGs will be able to sustain these highly leveraged capital structures by shifting many market-related risks to purchasing utilities through the take-or-pay contracts necessary to arrange financing, thereby effectively utilizing the purchasing utility's equity for the EWG's financing.

Proponents of the Bill argue that utilities need not purchase power from highly-leveraged EWGs and would not be required to sign contracts with long-term take-or-pay or fuel-costs escalator clauses. But, based on my many years of experience in the electric industry, including my observations during many years of involvement in industry organizations, I do not believe that regulated utilities will be assured a real choice about whether to contract for EWG power or on what terms. Developers offer capacity to a utility at a price that may appear to be lower than the long-term cost to the utility of building that capacity, and some regulatory agencies could well determine that a utility's failure to take advantage of this arrangement is "imprudent." There would no doubt be many variations of what takes place around the country depending upon different actions in different states.

My company and others have considerable experience under PURPA. In general, many companies have been required by state regulatory agencies to buy power from cogenerators for capacity that is not now needed and at prices higher than their real avoided costs of generating that power. As has been well documented, the PURPA requirement for use of as little as 5 percent of the steam created for industrial purposes has led to the construction of facilities far beyond the original concept of PURPA. The high costs paid by utilities under PURPA has been the result of the requirement under PURPA for commissions to make "avoided cost" determinations many years before it can be known what the true costs will be. LIkewise, this condition can exist with EWGs. Also, I believe many state regulatory agencies will not be able (or may be unwilling) to recognize the many offsetting costs to a utility of relying on EWGs. These costs include a higher cost of capital because, in the view of the financial community, the utility effectively would have become a guarantor of EWG debt. The utility also would incur additional operating costs arising from the inability to control completely the siting, design and operation of the EWG. It will be exceedingly difficult for state regulatory agencies to identify fully all.costs in weighing EWG offers and to give full recognition to the EWG's artificial tax advantages. The resulting "competition" is likely to be highly imperfect and biased in favor of the EWG.

I believe that the overall impact of this legislation at the state level will be to impose additional barriers to utilities building generation in the 1990s, just at the time when we should be expanding our systems for the needs of the next century.

Do we really want to risk degrading the existing vertically integrated electric industry -- with its high degree of reliability -- by displacing regulated utility investment with highly leveraged non-regulated facilities that have no obligation of public service? Many EWGs are likely to be mis-sited in terms of system needs, underbuilt in terms of reliability, overly dependent on a single fuel source, and difficult to dispatch. With EWGs, the issues of mandatory transmission access and wheeling are sure to adversely impact the regulated system and utility customesrs. In addition, these new so-called "competitive" forces would impose incentives which could work against the complex, voluntary information sharing, planning and coordination that now takes place within the regional reliability councils of NERC. These forces likewise could reduce incentives for joint, large scale collaborative research and development under the Electric Power Research Institute (EPRI) and other reliability-related joint industry activities. According to the Office of Technology Assessment (OTA) report, ". . . the costs and benefits of competition are very uncertain . . . Actual experience is limited, and little analysis has been performed . . . The benefits of competition are speculative and difficult to quantify. . ." (emphasis added) Why should the nation experiment in this critical area where the risks are great and the benefits likely to prove illusory?

It is worth noting the important differences between electric service and telephone and natural gas services. Important as they are, gas and telephone services are not generally deemed to be as essential as electric service. For example, telephone services and natural gas services are not built to meet instantaneous peak demands, nor or they required to do so.

The natural gas industry has built into its infrastructure large storage facilities in addition to the storage capability inherent in the pipeline. In addition, natural gas companies require large customers, such as the electric utility companies, to be able to rely upon a second fuel to use when gas is curtailed, which it most surely will be during heavy gas load requirements. So, the gas industry never intended to have the capacity to meet maximum load, nor is it required by regulation to do so.

The telephone industry has similarly designed its system to meet less than maximum capacity. How many times have we picked up the telephone and either found a busy signal on the other end or a voice that says, "The circuits are busy, call back later"?

Electric generation, however, must match the electric load exactly at every instant in time. That is done by very delicately balancing generation so that it exactly matches the load curve as it grows during the morning and early afternoon and drops off early afternoon and at night. If we turn the switch, we expect the light or the machine to come on immediately. Customers do not get a busy signal and would not accept it if they did.

Those who would compare the telephone and electric industries overlook the fact that our industry is substantially less centralized than is the telephone industry, even after the breakup of AT&T. The telephone industry is characterized by a "deregulated" handful of regional monopolies in which there is no competition with respect to local service. Further, the competitive entrants into the long-distance segment of the telephone industry do not enjoy any artificial competitive advantages due to highly-leveraged financing gained at the expense of pre-existing suppliers.

In conclusion, my company and the other regulated utilities in the Coalition oppose this bill because it will not produce genuine competition and because of the all-too-probable future displacement of reliable, regulated utility generation by more costly and less reliable facilities whose developers have no public service obligations.

The CHAIRMAN. You have just whetted our appetite for questions. We'll be back. [Laughter.]

Next, Joe Kearney who is CEO of PG&E-Bechtel Generating Company in Bethesda.

STATEMENT OF JOSEPH P. KEARNEY, CHIEF EXECUTIVE OFFICER, PG&E-BECHTEL GENERATING CO., ON BEHALF OF COGENERATION AND INDEPENDENT POWER COALITION OF AMERICA

Mr. KEARNEY. Thank you, Mr. Chairman, members of the committee. Good morning. My name is Joseph Kearney. As indicated, I am Chief Executive Officer of the PG&E-Bechtel Generating Company. I am appearing today on behalf of CIPCA, the Cogeneration and Independent Power Coalition of America and its affiliated group, the American Cogeneration Association.

I am here today to speak in favor of PUHCA reform. My company is involved in over 1,300 megawatts of private power generation. Myself, I have had over seven years of experience in the private power generation and cogeneration marketplace and over 18 years of experience in the energy and power business itself.

Despite, however, my experience in this industry and the significant amount of power generation capacity in PG&E and Bechtel Generating Company is involved, the opponents of PUHCA reform would have you believe that my company will not be a reliable supplier of power. I beg to differ with them. This is not an issue of whether we are different from the utilities in that regard. We can and will be as reliable a supplier of electric power as the existing regulated power plants can be.

In truth, however, I believe that our opponents are opposed to PUHCA reform simply because they fear competition. To those who would just say no to PUHCA reform, I urge them to listen to the many utilities that are seeking additional power supply options today. With over 100,000 megawatts of new generation capacity needed by the turn of the century, this country can ill afford to foreclose any reliable power supply option, regulated or unregulated. We are not in a position to discard alternatives and alternative producers. The opponents of PUHCA reform should not be provided an opportunity to veto the supply options available and desired by the rest of the utility industry.

CIPCA congratulates you, Senator, for furthering the debate over PUHCA reform with the introduction of the Competitive Wholesale Generation Act of 1989. Without PUHCA reform, competitive power producers will be significantly restricted in their ability to help the future capacity needs of the Nation's electric utilities and the customers that they serve. As we have already seen in the existing competition in the electric generation market results in greater efficiency, innovation, greater reliability and lower cost to customers.

CIPCA believes that PUHCA reform legislation in order to preserve this opportunity must be directed at ensuring fair competitive power generation markets. And in this context, I think there is no difference around this table. To this end, CIPCA supports the establishment of a truly level playing field including electric utility affiliates ownership of private power projects, myself included.

However, we do recognize that concerns have been expressed regarding the potential for unfair competition that could arise from the emergence of alternative suppliers of electricity. We believe that the PUHCA reform legislation does not affect this reality.

As a consequence, CIPCA urges you, however, to carefully consider these issues of unfair competition and respond where you deem appropriate. However, PUHCA reform should not be dependent upon our ability to create a perfect system for this complex industry.

While we agree that PUHCA reform must not exacerbate existing problems neither should it be held hostage pending resolution of totally unrelated issues. For example, PUHCA legislation does not and should not undercut state regulatory authority over utility capacity procurement plans. It in fact does not impact on those plans whatsoever, as I will indicate later.

But neither should PUHCA reform serve as a vehicle for mandatory transmission access. While transmission access is an issue of critical concern to many of our members, we believe it should be resolved outside of the PUHCA legislation.

Let me turn for a minute to some of the issues that were raised in last week's hearing. I was surprised to hear some of the arguments directed against PUHCA reform last week and again repeated this morning.

For example, the notion that the only advantage of private power producers is their ability to leverage projects is wrong for two very substantial reasons.

First, private power projects take risks off the utilities, not add to those risks, by their accepting of the construction cost risks, the completion risks, the technology performance risks and the operating performance risks and in some cases even the fuel risks. These risks are removed from the utilities. The concept that we are adding risks to the balance sheets of utilities is absurd.

Secondly, by correctly managing these risks—that is the risks that are now taken by the private power producer—by carefully managing these risks, innovative financings are possible, as has been indicated. However, these create real and not artificial cost savings which ultimately accrue to the consumers' benefits.

Also, another of our opponents' claims that creating an independent power supply option will lead inevitably to PURPA-like mandatory purchase obligation is absurd. The Competitive Wholesale Generation Act would do no more than provide willing buyers additional opportunities to purchase electricity if they want to and how they want to from willing private sellers. Simply put, if such a purchase is not a good deal for a utility, it should not be buying from that private generator. It should be using its own means to produce that additional capacity.

I notice that my red light is on, and let me just summarize.

You asked three questions, Senator, and in response to those, we clearly think that this legislation does not create a new opportunity for abuse. We think that the state procedures are adequate to protect against abuses on the regulatory front. And finally, I think that this particular piece of legislation can truly enhance our ability to supply power to this country at more cost effective rates than under the existing system.

Thank you very much.

[The prepared statement of Mr. Kearney follows:]

TESTIMONY OF
JOSEPH P. KEARNEY
ON BEHALF OF
THE COGENERATION AND INDEPENDENT POWER COALITION
OF AMERICA, INC.
BEFORE THE
COMMITTEE ON ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE
NOVEMBER 16, 1989

Mr. Chairman and Members of the Committee:

Good morning. My name is Joseph Kearney, and I am Chief Executive Officer of PG&E-Bechtel Generating Company. I am appearing today on behalf of CIPCA, the Cogeneration and Independent Power Coalition of America and its affiliated group, the American Cogeneration Association, representing about 500 corporate and individual members from a diverse spectrum of the electric power industry. CIPCA members include project development companies, electric and gas utility subsidiaries, equipment suppliers and manufacturers, fuel suppliers and companies involved in project finance. CIPCA and its member companies have been actively involved in the development of the independent power industry since 1980, and we appreciate this opportunity to appear before you today.

My company is involved in over 1300 Mws of independent power facilities representing with over $1 billion entering construction next year. Prior to joining PG&E-Bechtel, I served as Chairman and Chief Executive Officer of Coastal Power Production, a subsidiary of the Coastal Corporation actively involved in QF and independent power project development. Prior to that, I was Manager of Cogeneration Development for Fluor Corporation. All told, I have been involved in the cogeneration or private power business for seven years and have been involved in the energy and power business for over eighteen years.

Despite my experience in this industry and the significant amount of power generating capacity in which PG&E-Bechtel is involved, the opponents of PUHCA reform would have you believe that my company is not a reliable power supply option. Contrary to their contentions, plants built by my company and many other companies like mine present utilities with additional reliable supply alternatives.

In truth, I believe that the companies opposed to PUHCA reform truly fear competition. To those who would just say no to PUHCA reform, we urge you to listen to the many utilities that are seeking additional power supply options. With over 100,000 Mw of new generating capacity needed by the turn of the century, this country can ill afford to foreclose reliable power supply options. The opponents of PUHCA reform should not be provided a veto over the supply options available to the rest of the electric utility industry. It is also unfair to the ratepayers to deny them access to alternative suppliers that could be more cost effective than existing rate based plants.

All of us in the generation business should be working together at this time to fill the enormous need for new capacity faced by this country. To accomplish this, unnecessary regulatory constraints on private power projects must be eliminated. These regulatory constraints effectively bar the development of private power facilities by forcing the projects to assume complicated financial structures. The financial machinations necessitated by PUHCA will so severely limit the number of these facilities that they will never play a major role. Under current law, generation options to serve the future electric needs of utilities, practically speaking, are restricted to those facilities constructed under traditional rate based regulatory treatment and facilities that qualify under PURPA.

The enactment of the Public Utility Regulatory Policies Act (PURPA) in 1978, which removed PUHCA and other barriers to the construction of qualifying facilities (QFs), spawned the competitive power industry. Since PURPA, more than 27,000 Mw of electric generating capacity has been constructed and is now reliably operating, providing needed electricity to consumers across the nation. However, constraints on the size and technology of facilities qualifying under PURPA have restricted the development of competitive power and will do so more in the future as steam hosts for cogeneration facilities become more scarce.

The exemption from PUHCA now given to QFs under PURPA should be extended to any private power facility. This will allow the continued development of a competitive market in electric power generation. CIPCA believes that the development of such a market is in the public interest. Competition in the electric generation market will benefit consumers by providing the most efficient, reliable, environmentally sensitive and least cost power supply options. Removing facilities from the automatic cost plus recovery of rate based treatment shifts many of the financial risks of project development away from consumers and on to the shoulders of private power suppliers. Private power suppliers receive a contractual price for their power. This price cannot be changed to account for construction cost overruns, thus any overruns must be absorbed by the competitive developer. Similarly, private power suppliers are not paid for power that is not delivered, while under rate based construction costs are normally recovered whether or not the plant produces power.

There are many examples of private power providing low cost, reliable power, technological innovation and environmental benefits. In Freeport, Texas, Dow Chemical commenced selling capacity and energy to Houston Light & Power under a long term contract in January, 1985. The contract, at the time of signing, was at a more than 10% discount from full avoided costs, with indexed energy payments. The current price paid for energy under the contract is less than it was at the commencement of the contract in 1985. In the first four plus years of the contract, power was supplied during the on peak period at 99.99 percent of the contract level.

In Little Falls, New York a 4.5 Mw cogeneration project was developed by HYDRA-CO and supplies electricity and hot air to Burrows Paper in Little Falls, New York and electricity to Niagara Mohawk. The cogeneration plant replaced an obsolete and extremely inefficient gas and oil fired boiler and a PCB contaminated electrical substation. The paper mill has been able to approximately double its output, saving several hundred jobs, due to the installation of the plant.

In Ione, California, Reading Energy constructed a 15 Mw cogeneration facility that was the first use of circulating fluidized bed boiler technology with lignite fuel and one of the earliest uses of this technology on a commercial scale in the United States. Prior to the development of this facility the moist, low grade lignite coal of this California region was considered to be useless as a commercial fuel. The ash from this facility is being sold for commercial applications.

In Fort Fairfield, Maine, is a 30 Mw wood fired facility constructed by HYDRA-CO. The project has been in operation since 1987 and has consistently met all performance expectations. The plant burns whole tree chips and waste wood such as sawmill residue, slash and bark. The fuel that this plant consumes previously had no economic value. For example, slash is wood material previously left in the forest after logging operations.

Enron Cogeneration's 450 Mw facility in Texas City has experienced a 96.16 percent availability factor since its startup in May 1987, and has provided power to Texas Utilities with an on peak rolling average capacity factor at or above 100 percent throughout its life. In addition, the project has been called upon to provide increased contributions to ERCOT spinning reserve requirements since the startup of the South Texas Nuclear Plant.

A 49 MW project, developed by Reading Energy, located in the heart of Pennsylvania's hard coal region, burns anthracite reuse which is left over as the waste product from decades of coal mining operations. Using advanced circulating fluidized bed boiler technology with excellent pollution control equipment over the years this facility will consume the black mountainous banks of mine waste which have been an eyesore and environmental hazard to the local community for over a century. As these refuse banks are consumed, more than 100 acres of underlying land will be reclaimed, reforested and restored to their original natural beauty. Ash from the combustion process is used to safely backfill the scars left from abandoned strip mine operations on adjacent lands.

In Brawley, California, this plant, developed by HYDRA-CO, which is expected to come on line in December, burns agricultural waste products, creating electricity out of a waste disposal problem. Previously, these agricultural waste products were open field burned, creating a severe pollution problem for the already smog laden Imperial Valley

These are just a few examples of the approximately 2500 private power projects now operating nationwide. Competition has already proven its value. Reform of PUHCA will create more opportunities to consumers to realize the benefits of competitive power.

CIPCA congratulates you, Chairman Johnston, for furthering the debate over PUHCA reform with the introduction of the Competitive Wholesale Generation Act of 1989. Without PUHCA reform, the entrance of private power producers in the power generation business will be limited and the costs of power from those private power generators already in the business will be greater, Therefore, the ability of private power to effectively meet the future capacity needs of the nation's electric utilities and the customers they serve will be significantly limited. As we have already seen competition in the electric generation market results in greater efficiency, innovation, reliability, and lower costs for consumers.

CIPCA believes that PUHCA reform legislation must be directed at ensuring fair competition in power generating markets. To this end, CIPCA supports the establishment of a truly level playing field, including electric utility affiliate or subsidiary ownership of independent power projects. However, we recognize that concerns have been expressed regarding the potential for unfair competition that has arisen from the emergence of alternative suppliers of electricity. We believe that the PUHCA reform legislation does not affect this reality. CIPCA urges you to carefully consider these issues and respond where appropriate. However, PUHCA reform should not be predicated upon creating a perfect system.

While we agree that PUHCA reform must not exacerbate existing problems, neither should it be held hostage pending resolution of unrelated issues. For example, PUHCA legislation should not undercut state regulatory authority over utility capacity procurement plans. But neither should PUHCA reform serve as a vehicle for mandatory transmission access. While transmission access is an issue of critical concern to many CIPCA members, we believe it should be resolved outside PUHCA legislation.

I was surprised to hear some of the arguments directed against PUHCA reform at last week's hearing before this Committee. For example, the notion that the only advantage of private power producers is their ability to leverage projects is wrong for two substantial reasons. First, private power projects take risks off the utilities by accepting the construction cost and completion risks, technology performance risks, operating performance risks and in some cases fuel risks.

Secondly, by correctly managing these risks, innovative financings are possible which create real not artificial cost savings ultimately accruing to the ratepayers benefits.

Also, the claim that creating an independent power supply option will lead inevitably to a PURPA-like mandatory purchase obligation is absurd. The Competitive Wholesale Generation Act would do no more than provide willing buyers additional opportunities to purchase electricity -- if they want to and how they want to -- from willing private sellers. Simply put, if such a purchase is not a good deal for a utility, it should not be buying from private generators.

The opponents also indicate that PUHCA reform would divest utilities of their role in power supply planning. The contrary is true. PUHCA reform provides utilities with greater flexibility and more options. It will simply offer utilities an additional option. Properly designed competitive bidding or other supplier selection mechanisms will ensure utilities the ability to develop the ideal generation mix. Utilities will continue, as Virginia Power has clearly demonstrated, to have the option to build, if that option best meets the utility's needs and its obligation to serve. In addition, we have seen utilities and state regulators freely exercising their planning roles by establishing purchasing programs that very consciously reflect their assessment of the timing of new capacity, the type of generation capacity and preferred fuel types and location of new capacity.

Finally, contrary to some, we do not believe that state regulatory authority will be eroded by PUHCA reform. In fact, we would support clarifying the Johnston bill, if necessary, to ensure that existing state authority with respect to prudence reviews, least-cost planning, competitive bidding and similar regulatory powers is preserved.

I urge this Committee to move quickly to approve legislation amending PUHCA. Thank you for the opportunity to appear before you today, and I will be happy to answer any questions.

The **Chairman**. Thank you very much, Mr. Kearney.

Next we will hear from Bill Berry who is Chairman and CEO of Dominion Resources in Richmond.

STATEMENT OF WILLIAM W. BERRY, CHAIRMAN AND CHIEF EXECUTIVE OFFICER, DOMINION RESOURCES, INC., ON BEHALF OF THE UTILITY WORKING GROUP

Mr. **Berry**. Thank you. I appreciate the opportunity to appear today on behalf of the Utility Working Group, a coalition of 33 utilities and holding companies, and growing.

The **Chairman**. Now, let's see. You have 33 and you have 28.

Mr. **Berry**. Thirty-eight.

The **Chairman**. Thirty-eight, okay. He's ahead. [Laughter.]

Mr. **Berry**. The coalition is interested in increasing opportunities for competition in the supply of electricity to utilities.

The Utility Working Group strongly supports legislation to amend the Public Utility Holding Company Act of 1935, and we commend you for introducing this amendment that is contained in S. 406.

A competitive market in generating capacity already exists, and independent producers are providing a growing amount of capacity. But today's market is practically limited to qualifying facilities under PURPA, many of which are basically power plants with contrived or uneconomic cogeneration. This arrangement imposes unnecessary costs and dead weight losses on the American economy.

The issue before Congress is not whether there will be competition in capacity supply. The issue is whether that competition will take place on terms that will better serve electricity customers. Freeing exempt wholesale generators from the Holding Company Act is the crucial step in avoiding the needless costs of the PURPA based market and allowing competitive power producers to make a grater contribution to meeting future power demands.

In the coming decade substantial amounts of new capacity will be required, and some companies, including my own, are actively expanding their generation resources. We want to be able to get part of our capacity requirements in the competitive market. We want a market structured to give our customers the lowest cost consistent with reliability.

I am unable to fathom why some utilities who project no capacity needs for themselves in this century are striving to prevent a reform that utilities engaged in adding capacity now want and now need. Amending the Holding Company Act merely gives utilities an improved option for meeting their capacity needs. It does not rule out utility participation in supplying its own needs or traditional utility construction. It does mean that proposals for utility construction will be subject to a market test that will help to assure a least-cost program for meeting growing demand.

Whether competition actually provides cost advantages is not an abstract or a theoretical issue. You have concrete evidence in the buying decisions of Virginia Power and at least 15 other utilities. If there is an advantage for our customers in buying, then we buy. And Virginia Power has contracts for over 3,000 megawatts. If there is no advantage to buying, then we don't buy. And Virginia

Power has 1,400 megawatts under construction just completed or awaiting regulatory approval.

When utilities choose to buy from independent producers, they can do so on a basis that allows continued reliability. Non-price factors related to reliability must be considered along with price. Contracts must be structured to encourage faithful performance. Solicitations must specify the project characteristics that the utility demands. And utilities can protect reliabilities as well. With sensible policies, buying capacity need not compromise the reliability of service.

The market that will best serve electricity customers should be open to all producers for fair competition. That means, first, that utility affiliated companies must be able to participate in the market, but they must compete on the basis of economic efficiency. Market results must not be distorted by unfair self-dealing or ratepayer subsidization or preferential transmission access.

I believe there is adequate regulatory authority to preclude these abuses. Regulators establishing and administering bidding systems can prevent or police self-dealing. Regulators with their ratemaking powers and the right to review affiliate transactions can forestall ratepayer subsidies. And the FERC in administering the Federal Power Act can and must refuse market pricing when market power can be exercise.

A second requirement for an open and efficient market is increased transmission access. The Utility Working Group members recently submitted to FERC a statement of principles aimed at securing on a voluntary basis transmission services for suppliers to utilities. We welcome the recent report of the FERC Transmission Task Force as a first step in the FERC process leading to expanded transmission access. We expect to encourage and support that process.

At the same time, though, we urge you not to include transmission provisions in this Holding Company Act amendment. Any attempt to do so would draw Congress into a morass of economic and technical complexity that is much better addressed in an administrative setting. Moreover, including the difficult and controversial issues of transmission would certainly delay and perhaps eliminate large gains for customers through more efficient competition.

I see the benefits of competition being achieved by a series of discrete, incremental steps that should be taken as soon as reasonably possible without trying to settle all the issues at once. Reform of the Holding Company Act is the most important of these incremental steps, and it is right for action now. The companies in the Utility Working Group hope you will take action soon. The sun is beginning to shine on this proposal. [Laughter.]

[The prepared statement of Mr. Berry follows:]

STATEMENT OF WILLIAM W. BERRY
BEFORE THE
COMMITTEE ON ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE
NOVEMBER 16, 1989

I am William W. Berry, Chairman and Chief Executive Officer of Dominion Resources and Chairman of Virginia Power. Virginia Power has purchased more generating capacity through competitive bidding than any other utility. Dominion Resources, through its Dominion Energy and Dominion Capital subsidiaries, is one of the largest suppliers of non-utility power in the United States.

I appear today on behalf of the Utility Working Group, a coalition of 33 utilities and utility holding companies interested in expanding and improving the opportunities for competition in the supply of electric generating capacity and energy to utilities.

The Utility Working Group has continually grown and now includes the following members:

Arizona Public Service Company, Baltimore Gas & Electric Company, CMS Energy/Consumers Power Company, Duke Power Company, Duquesne Light Company, Entergy Corporation, Inc., Arkansas Power and Light Company, Louisiana Power and Light Company, Mississippi Power and Light, New Orleans Public Service, General Public

Utilities Corporation, Jersey Central Power and Light Company, Metropolitan Edison Company, Pennsylvania Electric Company, Nevada Power Company, New England Electric System, Granite State Electric Company, Massachusetts Electric Company, Narragansett Electric Company, New England Power Company, Northern States Power Company, Northern States Power Company -- Wisconsin, Orange and Rockland Utilities, Inc., Pacific Gas & Electric Company, PacifiCorp, Pacific Power & Light Company, Utah Power and Light Company, Portland General Electric Company, Public Service Company of Indiana, Inc., Public Service Company of New Mexico, Sierra Pacific Power Company, Dominion Resources and Virginia Power.

The Utility Working Group strongly supports legislation to amend the Public Utility Holding Company Act of 1935. We see provisions of that Act as the most important impediment to the development of broader and more efficient competitive markets that will allow utilities to provide reliable service at lower costs to their customers.

The problem with the Holding Company Act is that, for practical purposes, it now restricts the competitive market to Qualifying Facilities under PURPA. True cogeneration and small power production are inherently limited resources so that most capacity now being developed involves more or less contrived steam uses that are merely a ticket into the market.

Potentially valuable projects are lost and competition is diminished in cases where developers cannot find a qualifying steam use. Squeezing under the PURPA umbrella is especially difficult for coal-fired baseload units and gas-fired peaking units that may be especially appropriate to give utilities their most desirable capacity mix. For coal units, the requirement for a steam host exacerbates siting problems and for peaking units contriving a steam use is next to impossible. Even when steam uses can be contrived, the cogeneration requirement unnecessarily increases the cost of capacity.

The effect of broadening the market is bound to be lower costs to utility customers and improved competitiveness for our economy.

Accordingly, Mr. Chairman, the Utility Working Group welcomes and appreciates your action in introducing the amendment to the Holding Company Act contained in S. 406 providing for Exempt Wholesale Generators. We hope that your proposal will be the basis for Congressional action to expand the benefits for electricity customers of free and fair competition in capacity supplies.

Utility Working Group companies are interested in having improved opportunities to purchase needed capacity in competitive markets. We do not wish to rule out, either for ourselves or others, the participation of the utility in providing future capacity for its own customers. Virginia Power is in fact pursuing a policy of both capacity purchases and traditional utility construction -- choosing, in each case, the option that will best serve its customers. The legislation to amend the Holding Company Act will simply broaden the options available to utilities for adding needed generating capacity. The choice of how those options are used should remain with the utilities within the regulatory context in which they operate, as it would under the proposed amendment.

UWG members are also interested in increased opportunities to develop independent projects for utilities. We want the right for utility-affiliated companies to participate in the market and we want competition that is fair and based on economic efficiency.

We share the view of producers not affiliated with utilities that the market results must not be distorted by ratepayer subsidies, by unfair self-dealing or by discriminatory access to transmission services. If there is any disagreement in this area, it is not about the objective but about the means to assure that it is achieved.

Amendment of the Holding Company Act would not be an isolated action, but rather one of a number of related, incremental steps toward enhancing competition in capacity supply.

The UWG supported action by the Federal Energy Regulatory Commission to allow competitive bidding to set the prices and terms and to pick the winners for supplying capacity to utilities. While the proposed FERC rule has not been adopted, FERC has made it clear that competitive bidding is permitted under its rules. This has cleared the way for widespread adoption of competitive bidding by state regulators, thereby providing a major improvement over the previous system of pricing by administrative determination of avoided cost and first-come-first-served selection of suppliers.

The UWG also supports broadening the competitive market by increasing transmission access as a separate policy action. As Virginia Power's experience has demonstrated, strong competition is possible without any change in transmission access. In Virginia Power's 1988 solicitation, more than 70 percent of the capacity bid, representing some 10,000 megawatts or nearly 6 times our need, was offered by producers proposing to build within our service territory who did not require third party transmission services. For producers within our territory, Virginia Power stood ready to to provide any needed transmission and took account of the cost of doing so in our bid evaluation.

In most circumstances, effective competition is possible today. And it follows from that fact that significant gains for customers can be achieved by amendment of the Holding Company Act independent of any increase in transmission access. These benefits should not be lost or delayed by unnecessarily linking them with the complex and controversial reform of transmission access.

On the other hand, while competition is possible in most cases under the existing transmission regime, yet another increment of gains from competition can be realized through increased transmission access. Some utility buyers have service territories that do not allow a sufficient number of projects to be located within their borders. Some producers have fixed locations outside the service area of the utility seeking power. Even when there is strong competition without improved transmission access, even better results for the buying utility and its customers can be expected if potential winning bidders are not excluded by a lack of transmission services at appropriate prices.

UWG members recently submitted to FERC a statement of principles for increased transmission access on a voluntary basis. These principles call for utilities to provide suppliers to utilities with firm, long-term transmission service at embedded cost if transmission system improvements are not required, and at long-run incremental cost if improvements are necessary. The principles also contemplate that needed transmission improvements would be made if the required regulatory permissions were received.

We welcome the recent issuance of the report of the FERC task force on transmission. We believe the report represents the first step in a FERC process to expand transmission access that we expect to encourage and support. Electricity customers will be best served if transmission reform proceeds in this manner at its own pace, rather than through legislative action.

Amending the Holding Company Act is indispensable, but it is not sufficient to broaden the competitive power market. Independent producers which are not Qualifying Facilities under PURPA must also be able to price their power at market rates.

FERC, in considering market pricing both in a proposed rule and in individual cases, has made it clear that market pricing would be permitted only when the seller was not in a position to exercise market power. This policy, which the UWG fully supports, provides an important protection against the possibility that producers freed from the Holding Company Act would be able to profit from unfair competition. For example, a utility-affiliate that obtained an unfair market advantage through preferential access to the utility's transmission lines should not, and would not, be granted market pricing.

A competitive market in electric generating capacity exists already and is growing rapidly in geographical extent and in the amount of capacity being provided to utilities. I would argue that the issue before the Congress is not whether there will be competition in capacity supply, but whether that competition will take place on the terms that will better serve electricity customers and the American economy. Failure to pass the amendment before you will not end competition. But passage of this amendment will allow competition to work much better than the PURPA-based market we have today.

Nevertheless, many of the objections to this amendment are based on questioning competition itself. It may be helpful therefore to offer some perspectives drawn from the experience of Virginia Power and other UWG members on issues that have been raised concerning competition in capacity supplies.

Many utilities with capacity needs want the option of buying capacity in a competitive market.

Virginia Power is experiencing strong growth in demand and will need to add about 6000 megawatts of additional generating capacity by the turn of the century. As a benchmark, 6000 megawatts is about the present size of the Potomac Electric Power system serving the District of Columbia and portions of Maryland. We believe that having the option to buy part of this large capacity need in a competitive market is advantageous to both our customers and shareholders.

In our 1988 solicitation, we received bids for more than 14,000 megawatts of capacity to meet our request for 1750 megawatts. In our current solicitation for 1100 megawatts, it appears that the ratio of bids to need will be at least as high.

Strong competition among producers fosters creativity and efficiency that reduces our buying cost. And buying competitively allows us to select the projects that will best combine low cost with reliability over long-term contracts.

Buying capacity also has two more important advantages. It relieves us of part of the very large financing burden we would otherwise face and it reduces the net risks involved in adding capacity.

In their buying decisions, utilities are providing real-world confirmations of the advantage of capacity purchases.

You have heard -- and will hear -- utilities that have no projected capacity needs in this century arguing that competition will not provide real efficiency gains. Of course, this flies in the face of both economic theory and experience in other businesses which suggest that where competition is possible, it produces the best results. Taking a broad view, recent developments throughout the world seem to be strongly affirming the superiority of market processes.

Fortunately, in judging competition in the electric industry, you do not need to rely on theory or on extrapolations from other experience. Virginia Power evaluates the bids it receives and buys capacity from independents only when it provides an advantage for our customers. If, for whatever reason, the market at any particular time is not offering a better deal than utility construction, we do not buy capacity -- either from Qualifying Facilities or from non-QF Independent Power Producers.* In fact, Virginia Power and at least 15 other utilities -- some in the UWG, some not -- have chosen to buy capacity from independent producers. And in their decisions, you have real world evidence of the benefits of competition.

In my view, there is no valid basis for the suggestion that any advantage independent producers have in their cost of capital should be disregarded because, somehow, it is not real. Every industry and business has capital costs and a capital structure that are more or less appropriate to it. Independent producers typically have higher costs of equity and debt capital and the opportunity to use greater debt leverage than utilities. Whether and to what extent this situation results in lower average capital costs varies from case to case. Lower capital costs that do occur are as real and worthy of consideration as any other cost difference.

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*The only purchase from QFs that is mandated is of energy, which would not normally support any new capacity development. Capacity payments do not have to be made unless the capacity is needed and is not more costly than the best alternative.

The type of contracts being signed between independent producers and utilities nowadays are not hell-or-high-water, take-or-pay contracts. They are performance-based contracts, akin to contracts for services that no one thinks of capitalizing. They should not have adverse effects on the buying utility's capital structure or costs. If, nevertheless, a small portion of the buying utilities' payment liabilities are viewed as debt, the utility would simply need to consider the related cost in its evaluation of whether to buy or build. Utilities are quite capable of doing that.

Utilities can still build capacity for their own needs if that is advantageous.

In Virginia, the practice under a competitive bidding policy approved by the State Corporation Commission is for Virginia Power to take bids on its needs and to consider those bids in the light of its estimate of its cost of building capacity under traditional regulation. Neither the utility nor any affiliate participates in the bidding. To the extent that buying is not advantageous, Virginia Power rejects the bids and proposes to build under traditional regulation. The upshot is that while Virginia Power has purchased about 3000 megawatts of capacity in competitive markets, we also have about 1400 megawatts of utility capacity recently installed, under construction or proposed for regulatory approval.

In some other states, the practice is for utilities or their affiliates to participate in the bidding -- which of course requires special regulatory attention to ensure fairness. But with either approach, the utilities remain as a potential provider of capacity for their own needs. And, especially in the early stages of development of competitive capacity markets, their regulators are likely to insist that they do so.

Buying provides a valuable new option. It does not and should not rule out utility building. It does, however, subject proposals for utility building to a market test that some utilities may find uncomfortable. But a market test for utility building, together with competition among producers, will help assure that the supplies needed -- after cost-effective conservation and load management -- are provided at the lowest cost consistent with reliability.

Competition helps utilities to meet demand growth at the lowest cost.

Competitive markets providing least-cost capacity supplies are being integrated with demand-reducing programs in various ways. In some states, demand-side measures of conservation and load management are, or may be, included in bidding systems along with additional supply. In other cases, demand measures are considered in separate bidding systems or are developed administratively and subtracted from the amount of capacity to be provided by purchases or utility construction. The existence of market-price benchmarks provides an improved basis for identifying cost-effective conservation and load management programs.

Factors related to reliability can be adequately considered in capacity purchases.

There is virtually universal agreement that electric generating capacity is a multifaceted asset that cannot be purchased on the basis of price alone. Every bidding system provides for the consideration of a variety of non-price factors in considering bids. Every utility's solicitation and contracts will include the specifications that it, and its regulators, consider necessary and appropriate for purchased capacity.

The utilities and their regulators are still learning how best to handle non-price factors. There are important issues about the factors that should be considered, the weights they should have and the extent to which the evaluation system should be prescribed and revealed in advance. As the system shakes down, there will certainly be problems and failures of specific projects. But the object in a buying system should not be to avoid all failures but to assure that the utility can provide reliable service while gaining the cost advantages of competition. An absence of failures would reflect contracts that are too fat for efficient producers and would remove an important spur to economic efficiency.

Virginia Power's approach is to develop a defense in depth consisting of four elements:

- * We place substantial weight on factors related to reliability in our bid evaluation.
- * Our contracts include incentives for good performance over the long-term and avoid a placement of risks that can make projects uneconomical through no fault of the producers.
- * We are acquiring a portfolio of projects of modest size and diverse ownership that would allow us to absorb the failure of any single project or producer.
- * We have a contractual right to acquire, at fair market value, and to operate a failing project needed to maintain our service.
- * In what is probably a transitional measure, we incorporate in the amount of capacity we purchase an allowance for attrition during capacity development. The uncertainty about producers' ability to develop projects, and, accordingly the need for this type of allowance, will be lessened when the requirement for a steam host is removed, when barriers to producers' ability to become an IPP are eliminated, when broader transmission access is provided, and when the track records of producers become established.

Virginia Power's contracts for capacity brought in the competitive market provide, for practical purposes, full economic dispatch and include conditions for the smooth integration of the purchased capacity into system operations.

With competitive purchases, regulators continue to play a central role.

Competition in capacity supply is in no sense an effort to avoid or escape proper regulation. Regulators make the initial decision to require or allow competitive capacity purchases.

Regulators establish the framework of the market, sometimes with comprehensive and specific rules and sometimes -- more advisedly -- with a broad set of policies. Regulators exercise oversight of the market and of the bid evaluation process, with varying degrees of involvement. Regulators can and do judge whether competition and the absence of market power provide adequate protection to utility ratepayers. Regulators will consider the results of the bidding when the costs of the purchases come up for inclusion in retail rates, if not before. And regulators typically have the right to institute a review of the buying system and of the prudence of utility purchases of capacity at any time.

Generation is no longer a natural monopoly and ratepayer interests can be amply protected by competition. And this fact relieves regulatory burdens by eliminating the need for traditional regulatory reviews in the areas where market forces are effective. But as long as electricity distribution retains characteristics of a natural monopoly, economic regulation continues to have a vital role in protecting utility customers.

Far from expecting regulators to be excluded, some utilities fear they may become too deeply involved in picking winners in competitive bidding. This, indeed, may be a danger. But the probability of undue regulatory control would seem to be no greater than if the utility were seeking to meet its needs with traditional building.

Competitive capacity markets allow an improved treatment of risk.

Three of the largest sources of risk for utilities building capacity have been construction cost, timely completion and operating performance. With competitive buying, those risks can be shifted to independent producers which have both the ability and the incentive to control those risks. Of course, the price of capacity will be sufficient to compensate efficient producers for the risks they bear -- providing an appropriately balanced relation of risk and reward.

The competitive market -- with its pressures for entrepreneurial creativity and opportunities for profits commensurate with the risks taken -- will probably provide a better environment for the introduction of new generating technologies that involve both substantial risks and the possibility of substantial rewards.

Utilities will continue to be exposed to the risks that their forecast of demand or their choice of fuel mix will be wrong. But in those respects, they are in the same position as they would be if they were meeting their needs through traditional building. Utilities acquire a risk that independent producers will not perform under their contracts, but this risk can and should be controlled by the utility as I described earlier.

On balance, with competitive markets, risks are better allocated to those best able to bear and control them, and the problem of the asymmetric treatment of risk and reward that deters construction of capacity by utilities is substantially reduced.

Buying utilities can get the type of capacity they need and want.

It is sometimes suggested that competitive markets will result in over-reliance on natural gas and that profit-making companies will not include in their projects features that utilities view as necessary. But the fact is that the characteristics of the projects are within the control of the buying utilities, subject to state regulatory policy. Buying utilities can establish reasonable specifications for independent projects. Buying utilities can control the kind of fuel mix they get -- either by specifying fuels or by announcing preferences to be applied in the bid evaluation.

For example, in its 1988 solicitation, Virginia Power announced that it would give preference to coal-fired projects in its bid evaluation. As a result, about 70 percent of the energy from the projects purchased through this solicitation will be provided by coal.

Regulators have, or can have, the authority to prevent unfair self-dealing and cross-subsidization.

Two of the key concerns about competition in which utility-affiliates participate relate to self-dealing and ratepayer subsidies.

For utilities operating outside the utility service area and outside an area in which the utility controls or influences transmission access, issues of self-dealing simply do not arise. When self-dealing is possible, the utility's regulators are able to decide in defining the bidding system whether and on what terms the utility may participate. Virginia Power's desire and the Virginia State Corporation Commission's policy is that Virginia Power and its affiliates do not participate in Virginia Power's solicitations. In some other states, the utilities wish to participate directly or through an affiliate and their regulators may want or require them to do so. This is a matter that is best decided by the utilities and regulators involved. Utility regulators are fully able to prevent or police transactions involving self-dealing between a utility and an affiliated supplier.

Whenever a utility or its affiliate engages in non-utility business, the possibility of ratepayer subsidies becomes an immediate focus of attention. Regulators have had extensive experience in dealing with the issues presented by non-utility activities. It is noteworthy that the Executive Committee of the National Association of Regulatory Utility Commissioners recently opposed the adoption of a proposed Securities and Exchange Commission rule related to diversification by exempt holding companies, arguing that the "states are uniquely qualified to monitor diversification and prevent abuses."* Thus, regulators would seem to have ample authority through their regulation of the utility and through their right to review transactions between the utility and any affiliate to preclude any ratepayer subsidization of utility-affiliated Exempt Wholesale Generators.

In the case of Dominion Resources, the Virginia State Corporation Commission undertook a lengthy and detailed investigation at the time our holding company structure was established. The Commission ended up prescribing a "wall" between Virginia Power and any non-regulated affiliate such that no services can be provided by Virginia Power except by specific Commission authorization. In fact, there are no regular transactions between Virginia Power and our non-regulated subsidiaries. Other arrangements to prevent cross-subsidization that involve less complete separation between the utility and its affiliate are no doubt also possible. As in the case of self-dealing, this is a matter that is within the responsibility and authority of state regulators and legislators.

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* Letter of August 9, 1989 to David Ruder from William A. Badger and Joshua M. Twilley.

The considerations I have cited show that the competitive market is a valuable option, that it does work in the interest of utility customers and that the concerns about it are either unfounded or subject to appropriate regulatory controls.

So I return to the point that the benefits of competition can be increased by opening the market to all producers by freeing Exempt Wholesale Generators from the restrictions of the Holding Company Act. In Virginia Power's solicitations, we have heard again and again of the costs and difficulties producers were having in finding steam uses to gain qualifying status under PURPA. In Dominion Resources' own independent power business, we have experienced problems in developing a steam use that in some cases turn a difficult siting problem into an insurmountable obstacle.

We also know first-hand of the near-impossibility of developing non-QF independent power projects under the Holding Company Act as it now exists. In Virginia Power's 1988 solicitation, despite strong interest in developing IPP projects, only one project has survived as an IPP. The excellent hydroelectric project in Vidalia, Louisiana, in which Dominion Resources is half-owner, was nearly stillborn because of difficulties with the Holding Company Act. We could not develop additional independent power projects on the same legal basis as the Vidalia project.

Freeing Exempt Wholesale Generators from the Holding Company Act will allow a competitive market that is in place and expanding to serve the American people much better that it can under present law. This reform cannot happen too soon.

The **CHAIRMAN**. Thank you, Mr. Berry.

Next we will hear from Charles D. Gray who is Assistant General Counsel of NARUC.

STATEMENT OF CHARLES D. GRAY, ASSISTANT GENERAL COUNSEL, NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS

Mr. **GRAY**. Thank you, Mr. Chairman, members of the committee. I am standing in for Commissioner Badger who is at our convention in Boston and wanted to be here, but couldn't get away.

I have been Assistant General Counsel at NARUC for 10 years, and I would like to briefly describe our position on the legislation before the committee.

In July our association adopted a resolution which opposes the enactment of this legislation unless and until the bill is amended to specifically preserve the legal authority of the respective state commissions to ensure that the sale of power by new entrants into the market is in the interest of retail ratepayers.

In short, our answer to the question that opened today's hearing is that the PUHCA obstacles to entry should not be removed until state jurisdiction is affirmed and clarified. It can't be left to continuing litigation. And that seems to me to be the only alternative we have to enacting legislation which specifically addresses these issues.

Our resolution describes four specific protections for state regulatory authority that must be included in any legislation which reduces or removes PUHCA's barriers to wholesale market entry. I would just like to briefly list them in my time, and we can perhaps come back if there is a little more.

Specifically, the bill must be amended. First, Congress must ensure the right of each state commission to review the prudence of the wholesale purchasing practices of each distribution utility subject to the state commission's authority. The shorthand for that has been to codify Pike County. I think it is a bit more than that, but that is the way it has been described.

Second, Congress must enact specific provisions to preserve the right of each state commission to conduct bidding programs and least-cost planning, to determine the appropriate mix of generation as a matter of fuel and technology choice and as a matter of ownership, to take actions to ensure system reliability, to restrict or prohibit affiliate transactions and to approve or disapprove the transfer of assets from a utility to another party free from preemption.

Third, Congress must provide a right of access enabling state commissions to review the books and records of holding companies and all holding company subsidiaries for the purpose of investigating and regulating cross subsidy and self-dealing.

Fourth, in the case of integrated multistate holding companies, Congress should authorize regional compacts for those states who have jurisdiction over retail subsidiaries of the holding companies for the purpose of regulating the allocation of costs of purchase from exempt wholesale generators and for the purpose of reviewing the prudence of wholesale purchases by the holding company.

Returning to these points individually, as I understand it, the purpose of S. 406 is to increase the number of potential wholesale suppliers. We have heard that these state issues are separate and unrelated to the purpose of this legislation and that the current uncertainty, or murkiness I guess is the word, should be left in place.

It seems to me, however, that because distributors will remain natural monopolies in their service territories under virtually anyone's view of the future, the result of allowing greater wholesale generation or increasing the number of generators will bring added pressure on state regulators to review the power supply contracts entered into by distributors to determine if these contracts are in the interest of the distributor's consumers.

Accordingly, specific affirmation of state regulatory authority is not unrelated or tangential to the purpose of S. 406. It is fundamental to an industry reliant on wholesale contracts rather than retail rate base for the acquisition of new power supply.

Nor is the so-called savings clause contained in S. 406 sufficient to ensure that state regulation is not preempted by subsequent action by the FERC or the courts. This section simply leaves the current uncertainty with respect to state regulation of wholesale purchases in place. At a minimum this section of the bill should be amended to read "nothing in any provision of Federal law", rather than this act, "shall preempt state regulatory authority."

Moving on to the second item on our list, the purpose of the second provision is to protect state regulators from Federal interference as they continue their efforts to adopt their methods of regulation to new types of competition in generating markets.

Essentially what this would do would be to ensure that either this legislation, if enacted, or the Federal Power Act as it now stands could not be used as a sword to interfere with or preempt state bidding programs, acquisition plans, least-cost planning, or decisions by states to determine that certain fuels should provide only certain percentages of new capacity. Essentially it has been called a catchall, but it is a very important assurance of what the states are going to be looking at in a market that is based on contract rather than retail rate base.

Turning to the last point on the multistate issue, the problem here is that under the Supreme Court's decision in Mississippi Power & Light, the Court has opened under the Federal Power Act a substantial regulatory gap in which nothing would be regulated. And if I could give a brief example.

Multistate holding companies can structure their operations, in order to acquire purchased power, through a non-state regulated subsidiary. There is nothing to prevent this if this legislation were to pass. The FERC would regulate the justness and reasonableness of the sale and allocate the costs of the purchase. The state commissions would regulate the costs of the retail subsidiaries, except under Mississippi Power & Light they couldn't regulate the cost of the purchased power. But no one would regulate the prudence of the holding company's purchase with reference to the company's other supply options.

We propose that the states be allowed to voluntarily create a regional body to do that, to look at the prudence of purchases of all sources of supply that come in to the holding company as a system rather than in to the distribution companies.

In closing, I think it is important that the members of the committee recognize that the state commissions are not opposed to greater competition in wholesale generating markets. Indeed, virtually all of the recent steps to open these markets to competitive pressures have occurred at the state commission level. To preserve this progress, the states need the explicit assurance from the Congress that their efforts will not be overturned by preemptive or prescriptive one-size-fits-all Federal decisions. In the view of the NARUC, the four elements of our resolution are necessary to provide this assurance and, therefore, must be included in S. 406 as the legislation proceeds.

Thank you for your time and attention.

[The prepared statement of Mr. Gray follows:]

UNITED STATES SENATE
COMMITTEE ON ENERGY AND NATURAL RESOURCES

TESTIMONY OF THE

NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS

1102 INTERSTATE COMMERCE COMMISSION BUILDING
P.O. BOX 684, WASHINGTON, D.C.

ON

S. 406
THE COMPETITIVE WHOLESALE ELECTRIC GENERATION ACT OF 1989

NOVEMBER 16, 1989

SUMMARY OF TESTIMONY OF THE
NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS
ON S. 406,
THE COMPETITIVE WHOLESALE ELECTRIC GENERATION ACT OF 1989

The National Association of Regulatory Utility Commissioners (NARUC) opposes the enactment of S. 406, The Competitive Wholesale Electric Generation Act of 1989 unless the bill is amended to specifically preserve the legal authority of the respective State commissions to insure that the sale of power by new entrants into wholesale markets is in the interest of retail ratepayers.

Specifically, the bill must be amended to protect State regulatory jurisdiction from Federal preemption or encroachment:

o First, Congress must ensure the right of each State commission to review the prudence of the wholesale purchasing practices of each distribution utility subject to the State commission's authority.

o Second, Congress must enact specific provisions to preserve the right of each State commission to conduct bidding programs and least cost planning; to determine the appropriate mix of generation, as a matter of fuel and technology choice and as a matter of ownership; to take actions to insure system reliability; to restrict or prohibit affiliate transactions; and to approve or disapprove the transfer of assets from a utility to another party, free from preemption under Federal statutes or the Commerce Clause.

o Third, Congress must provide a right of access, enabling State commissions to review the books and records of holding companies and all holding company subsidiaries, including non-regulated businesses, that transact business with the retail distribution company or EWG entity.

o Fourth, in the case of an integrated multi-state holding company, Congress should authorize regional compacts for those States who have jurisdiction over retail subsidiaries of the holding companies for the sole purpose of regulating the allocation of costs and/or the prudence of wholesale power purchases by the holding company.

The State commission members of the NARUC do not oppose greater competition in wholesale generation. However, legislation which encourages the expansion of wholesale generating capacity must protect the authority of the States to ensure that increased reliance on wholesale generation is in the interest of the public.

Mr. Chairman and Members of the Committee:

My name is Charles D. Gray, and I am Assistant General Counsel of the National Association of Regulatory Utility Commissioners (NARUC) on whose behalf I appear today.

The NARUC is a quasi-governmental nonprofit organization founded in 1889. Within its membership are the governmental bodies of the fifty States engaged in the economic and safety regulation of carriers and utilities. The mission of the NARUC is to serve the public interest by seeking to improve the quality and effectiveness of public regulation in America. More specifically, the NARUC contains the State officials charged with the duty of regulating the retail rates and services of electric and gas utilities operating within their respective jurisdictions. These officials have the obligation under State law to assure the establishment and maintenance of such energy utility services as may be required by the public convenience and necessity, and to ensure that such services are provided at rates and conditions which are just, reasonable, and nondiscriminatory for all consumers.

The NARUC deeply appreciates this opportunity to express our views on S. 406, the "Competitive Wholesale Generation Act of 1989" which would exempt wholesale generators of electricity from provisions of the Public Utility Holding Company Act of 1935 (PUHCA). In our view, there are few more important issues now pending before the Congress, the Federal Energy Regulatory Commission (FERC), and the State regulatory commissions than those raised by this bill: the future structure of the electric utility industry as we enter the 21st Century. And in our view, S. 406 goes to the heart of the ongoing debate on the future of the industry. The questions are both simple and profound: Is it in the interest of the economy, the industry, and utility consumers to disintegrate the electric utility business? How will a utility industry which acquires all or part of its new generating capacity through contract rather than construction perform its continuing obligation to provide reliable and affordable service? What can ratepayers hope to gain by allowing distributors of electricity to acquire power from affiliated "exempt wholesale generators" (EWGs)? Can unaffiliated EWGs provide beneficial competition in wholesale power markets without the assurance of reasonable access to their potential customers? How can we be sure that State regulators will have the legal authority to regulate the participation of monopoly distribution utilities in competitive wholesale markets?

S. 406 provides some answers to these important questions: It is in the public interest to reduce the PUHCA barrier to entry of wholesale generators, thereby further disintegrating the generation and distribution functions. Questions of contractual obligations and reliability of service will be worked out by the EWGs, the utilities, State regulators and the courts. There is no apparent problem with allowing both affiliated and unaffiliated EWGs to play in this market, even within the service territories of affiliated retail distributors, because State regulators will police any cross subsidy problems. EWG access to retail markets, if a problem at all, will be worked out by the FERC and the courts. And finally, questions of State authority to regulate utility participation in competitive wholesale markets should be left for the courts to decide.

In our view, S. 406's answer to the last question is clearly insufficient, which provides the basis of my testimony here today. Our Association has adopted a resolution (attached hereto) which strongly opposes the enactment of this legislation unless and until the bill is amended "to specifically preserve the legal authority of the respective State commissions to insure that the sale of power by new entrants into wholesale markets is in the interest of retail ratepayers." Our resolution describes four specific protections for State regulatory authority that must be included in any legislation which reduces or removes PUHCA's barriers to wholesale market entry. I would like to briefly describe these protections.

First, Congress must "ensure the right of each State commission to review the prudence of the wholesale purchasing practices of each distribution utility subject to the State commission's authority."

State jurisdiction to review the prudence of a distribution monopoly's acquisition of purchased power is now under attack. Despite their rosy testimony here last week, utilities have been relentless in their efforts to force State commissions to pass through the costs of purchased power in retail rates without any review of the prudence of their purchasing practices. Armed with the Supreme Court's decision in Mississippi Power & Light v.

Mississippi ex rel. Moore, utility litigants have continued to argue that because FERC has reviewed the reasonableness of a wholesale sale under the Federal Power Act, State commissions have no jurisdiction to review the prudence of the purchase, even if better sources of power were available from other suppliers.

As I understand it, the purpose of S. 406 is to increase the number of potential wholesale suppliers, thereby providing retail distributors new options for power supply. Because distributors will remain natural monopolies in their service territories, this result will bring added pressure on State regulators to review the power supply contracts entered into by distributors to determine if these contracts are in the interest of the distributor's consumers. Therefore, specific affirmation of State regulatory authority—to regulate wholesale purchases is not unrelated or tangential to the purpose of S. 406; it is a fundamental to an industry reliant on wholesale contracts rather than retail ratebase for the acquisition of new power supplies.

Nor is the so-called "savings clause" contained in section 4 of S. 406 sufficient to ensure that State regulation is not preempted by subsequent action by the FERC or the courts. This section simply leaves the current uncertainty with respect to State regulation of wholesale purchases in place. At a minimum, this section of the bill should be amended to read "nothing in any provision of Federal law shall preempt. . . .State regulatory authority." Clearly, it is preemption through construction of the Federal Power Act which is the issue here, and it must be addressed squarely if an industry based on wholesale supply contracts is to operate in the interest of utility consumers. In short, by opening up the possibility and indeed likelihood of more wholesale purchases, S. 406 must be amended to ensure that the monopoly purchasing powers of distribution utilities are not abused through preemption of State regulatory authority.

Second, Congress must enact specific provisions to "preserve the right of each State commission to conduct bidding programs and least cost planning; to determine the appropriate mix of generation, as a matter of fuel and technology choice and as a matter of ownership; to take actions to insure system reliability; to restrict or prohibit affiliate transactions; and to approve or disapprove the transfer of assets from a utility to another party, free from preemption under Federal statutes or the Commerce Clause."

The purpose of this second provision of the NARUC resolution is to protect State regulators from Federal interference as they continue their efforts to adapt their methods of regulation to new types of competition in generating markets. As the Committee heard last week, many States have begun processes to acquire new sources of supply through competitive bidding--a remarkable change from the way this industry has been regulated in the past. As a matter of definition, such competitive bidding systems involve distribution utility participation in wholesale power markets. Therefore the specter of Federal preemption, either through FERC actions or judicial decisions will be ever present. However, I don't think that I am overstating the case to say that Federal interference in these new programs would be disastrous. We are quite clearly in the experimentation stage with these programs as regulators and utilities grapple with questions of reliability, generation mix, fuels reliance, affiliate relationships, and a host of other issues. As these efforts proceed, I would expect that each State and each utility will develop resource acquisition plans which will be unique.

It is my understanding that the purpose of S. 406 is to foster greater competition in wholesale markets in ways that further these procompetitive developments at the State level, or at least that's what I heard from utility proponents of the bill in last week's hearing. If these two ideas, reduced Federal barriers to entry and competitive bidding at the State level, are to mesh, Congress must ensure that the State commissions are protected from the efforts of utilities and others to drag State decisionmaking into Federal court or the FERC. Let me provide an example: suppose a State commission were to conclude that it was appropriate to segment a given utility's acquisition of power so that no more than 50% of incremental capacity was provided by EWG gas-fired facilities, 25% provided by EWG waste-to-energy facilities, and 15% utility-owned generation (i.e. in retail ratebase), and 10% demand-side conservation investment, and further, that no EWG could be affiliated with the purchasing utility. Given the availability of EWG capacity in or near the service territory, there may well be disappointed bidders who are unable to obtain power sales contracts, or the purchasing utility may object to having its wholesale power contracts reviewed by a State on the basis of Mississippi Power & Light. In our view, it is absolutely imperative that any legal remedy they might have must be found in provisions of State law, enforced through the commissions and the courts, and not through a preemptive decision of the FERC or a U.S. District Judge construing the Federal Power Act.

Accordingly, S. 406, which is intended to permit these new third party generators to exist, must be amended to provide the assurance that State bidding programs and least cost planning efforts be free from Federal interference.

Third, Congress must "provide a right of access, enabling State commissions to review the books and records of holding companies and all holding company subsidiaries, including non-regulated businesses, that transact business with the retail distribution company or EWG entity."

Our third protection would require S. 406 to be amended to provide State commissions a means to enforce their subpoenas, document requests, discovery orders and the like against entities not physically present within the State, but doing business with, affiliated with, or otherwise affecting the price, supply, reliability or other relevant factors involved when an EWG sells to retail distributors. We do not intend that this protection create new substantive jurisdiction in the State commissions; rather, its purpose is to provide State commissions a procedural remedy in a Federal forum to enforce requests for information which are lawful under State law.

Perhaps the most straightforward way to implement our request would be simply to authorize Federal courts to enforce lawful State commission orders for access to the books and records of utilities, their out-of-State affiliates and EWGs. Our primary concern is that as drafted, S. 406 places no restrictions on the creation or operation of EWGs affiliated with retail distribution utilities, thereby leaving to State commissions the responsibility and obligation to ensure that utilities do not subsidize the operations of EWG affiliates to the detriment of ratepayers and independent generators competing with these affiliates. Again, let me provide an example of a situation which might well arise: suppose an EWG constructs a gas-fired facility to sell power to its affiliated retail utility. Suppose further that to meet competition from other EWGs, the parent holding company structures its gas purchases in order to supply the EWG plant on terms and conditions more favorable than the retail subsidiary is able to obtain for its own far larger gas requirements. Further suppose that when confronted with allegations of these practices provided by a competing EWG, the State commission issues a subpoena for the affiliated EWG's gas supply contracts, and the EWG, located beyond the jurisdiction of the State, refuses.

Or consider another example: suppose a retail utility operating in State A sends its engineering staff to State B to work on the development of an affiliated EWG located in that State. Suppose further that the only evidence of the staff's participation on behalf of the EWG is in State B. When confronted with an allegation of cross subsidy, the regulatory commission in State A examines the books and records of the retail utilities and finds that full engineering costs have been charged to the utility's ratepayers. The State commission issues an order for the books and records of the EWG, which is ignored.

In our view, if EWGs affiliated with retail utilities are going to be allowed to enter the power generation business, State commissions, and only the State commissions, must be given the statutory right to invoke the jurisdiction of a Federal District Court within the State to enforce its subpoenas and obtain documents and testimony in order to confirm or deny allegations of cross subsidy, and for other lawful regulatory purposes.

Fourth, "in the case of an integrated multi-state holding company, [the Congress should] authorize regional compacts for those States who have jurisdiction over retail subsidiaries of the holding companies for the sole purpose of regulating the allocation of costs and/or the prudence of wholesale power purchases by the holding company."

This last protection is intended to address the difficult issues raised when integrated multi-state registered holding companies participate in wholesale power markets. Under the Supreme Court's decision in Mississippi Power & Light, such companies may be able to purchase power from affiliated and unaffiliated EWGs with no State regulation of their purchasing decisions. To avoid State prudence regulation, a holding company could simply purchase power from third parties through an affiliate which is not subject to the regulatory authority of the State commissions in whose jurisdictions it operates retail subsidiaries. Under the logic of MP&L, the States would be required to pass through the costs of such purchased power once they had been allocated to the operating subsidiaries by an FERC allocation order.

Clearly, there is a large regulatory gap here: FERC would regulate the justness and reasonableness of EWG sales and the allocation of the costs, the individual State commissions would regulate the costs of the retail distribution subsidiaries (except, of course, these purchased power costs), but no-one would regulate the prudence of the holding company's purchases with reference to the company's other supply options. Here, it is very clear that the "savings clause" approach to State prudence-of-purchase authority is meaningless, unless the authors of S. 406 intend that section 4 of the legislation impliedly reverse the MP&L decision.

We propose to fill this gap through congressional legislation which would authorize the States in which the holding company operates to form regional regulatory bodies to review the prudence of any wholesale purchases the company may make for its system supply, i.e. to meet the collective need for power of its subsidiaries rather than an individual operating subsidiary's needs. These bodies would be formed voluntarily by the States, and if they so chose, they could regulate not only the prudence of wholesale purchases but could also allocate the costs of the purchases among the retail distribution subsidiaries. We would propose that no regional body could be established unless all of the States agreed, and further, that the decisions of the regional board be unanimous.

In closing, I think its important that the members of the Committee recognize that the State commissions are not opposed to greater competition in wholesale generating markets. Indeed, virtually all of the recent steps to open these markets to competitive pressures have occurred at the State commission level. To preserve this progress, the States need the explicit assurance from the Congress that their efforts will not be overturned by preemptive or prescriptive "one size fits all" Federal decisions. In the view of the NARUC, the four elements of our resolution are necessary to provide this assurance, and therefore, must be included in S. 406 as the legislation proceeds.

Thank you for your time and attention. I would be happy to attempt answers to any questions you may have.

Resolution on
Reform of the Public Utility Holding Company Act

WHEREAS, Legislation is pending before the Senate Committee on Energy and Natural Resources, S. 406, to amend the Public Utility Holding Company Act of 1935 (PUHCA); and

WHEREAS, The legislation would create a new category of electric generator called Exempt Wholesale Generators (EWGs) which would not be subject to the regulatory restrictions imposed on holding companies by PUHCA; and

WHEREAS, The purpose of this bill is to greatly reduce the barriers to entry for holding companies, including electric utilities, to enter wholesale markets and sell power to distribution utilities for resale to consumers; and

WHEREAS, The addition of new EWGs to wholesale markets subject to regulation by the Federal Energy Regulatory Commission (FERC) will erode State control of an increasingly large percentage of the cost of electrical service, particularly if the FERC and the Federal Courts continue to hold, in reliance on Mississippi Power & Light v. Mississippi ex rel. Moore, 487 U.S. __ (1988), that State commissions have severely limited jurisdiction to review the passthrough of purchased power costs in retail rates; and

WHEREAS, By permitting unrestricted utility ownership of EWGs, the legislation creates the opportunity for utilities to cross-subsidize their construction and operation of wholesale power facilities through their retail distribution rates, particularly utilities owning and operating EWGs which sell power to affiliated distribution companies; now, therefore, be it

RESOLVED, That the Executive Committee of the National Association of Regulatory Utility Commissioners (NARUC), assembled in its 1989 Summer Committee Meeting in San Francisco, California, strongly opposes amendment to the Public Utility Holding Company Act of 1935 unless provisions are included which specifically preserve the legal authority of the respective State commissions to insure that the sale of power by new entrants into wholesale markets is in the interest of retail ratepayers. Such provisions must:

1. Ensure the right of each State commission to review the prudence of the wholesale purchasing practices of each distribution utility subject to the State commission's authority; and

2. Preserve the right of each State commission to conduct bidding programs and least cost planning; to determine the appropriate mix of generation, as a matter of fuel and technology choice and as a matter of ownership; to take actions to insure system reliability; to restrict or prohibit affiliate transactions; and to approve or disapprove the transfer of assets from a utility to another party, free from preemption under Federal statutes or the Commerce Clause; and

3. Provide a right of access, enabling State commissions to review the books and records of holding companies and all holding company subsidiaries, including non-regulated businesses, that transact business with the retail distribution company or EWG entity; and

4. In the case of an integrated multi-state utility holding company, authorize regional compacts for those States who have jurisdiction over retail subsidiaries of the holding company for the sole purpose of regulating the allocation of costs and/or the prudence of wholesale power purchases by the holding company.

Sponsored by the Committees on Electricity, Energy Conservation,
and Finance and Technology
Adopted July 27, 1989

The CHAIRMAN. Thank you, Mr. Gray.

Finally, we have Scott Hempling, attorney with the Environmental Action Foundation here in Washington.

STATEMENT OF SCOTT HEMPLING, ATTORNEY, ENERGY PROJECT, ENVIRONMENTAL ACTION FOUNDATION

Mr. HEMPLING. Thank you very much, Mr. Chairman and members of the committee. My name is Scott Hempling. I am attorney for the Energy Project of Environmental Action Foundation. EAF represents consumer interests in electric industry restructuring litigation.

I commend the Chairman for his leadership in initiating this historic debate. Some have suggested that the electricity debate is a debate over two worlds: competition represented by utilities supporting Senate Bill 406, and no competition represented by the utilities opposing the bill.

That viewpoint rests on a false dichotomy. There are, in fact, three worlds: no competition, unfair competition, and fair competition. Senate 406 by freeing utilities and others to expand into new territories without advance review invites unfair competition.

Mr. Chairman, we face a unique period of corporate restructuring and consumer risk. During this period, the Public Utility Holding Company Act stands as the essential statutory protector of consumers, competition and regulatory effectiveness. The act bars utility acquisitions which monopolize new territories or new power sources. The act prohibits acquisitions which create any risks to consumers or investors. The act demands the utility acquisitions produce coordination efficiencies for ratepayers. It guards against corporate structures that make state regulation more difficult, and it limits utility speculation in unrelated ventures.

The utility's restructuring plans are essentially blocked or inhibited by the act, but instead of candid calls for repeal, utilities create corporate constructs and exempt them from the act. Utilities don't expand. They acquire exempt wholesale generators or they form independent power producers. A utility affiliate cannot be an independent power producer without being an oxymoron, an independent affiliate. Independent of what? When a utility with a distribution or transmission monopoly creates, finances, owns and controls another company, there is no independence.

Nevertheless, the bill creates a category, exempt wholesale generators, and sweeps into it every conceivable entity, single state utilities, multistate utilities, construction contractors, stock traders with excess cash, banks, foreign corporations, to name a few. Under the bill every one of these entities could enter the market anywhere, acquire as many wholesale utilities as they want and face no advance review under the Holding Company Act.

The result is a dramatic reduction in market accountability and public accountability. I'll give seven brief examples.

First, utilities can use their affiliates to discriminate against competitors in power purchases and in transmission access. A utility owner may simply discourage small power production by favoring its affiliate projects over unaffiliated ones.

The most dramatic case of this favoritism concerns fair access to bottleneck transmission facilities. These facilities are the highways of commerce in this industry. We cannot have competition in generation unless competing sellers can move their products to market. Therefore, we are unable to avoid linking the issue of utility creation of affiliates with the issue of nondiscriminatory transmission access. Competition exists only when competition is protected from anti-competitive behavior. That is not the effect of this bill.

Secondly, utility affiliates can become instruments of self-dealing. The problem of self-dealing is exemplified by a recent finding of the Michigan Public Service Commission. And I quote. "One must wonder whether Consumers' Power has once again negotiated with itself and lost." [Laughter.]

Mr. **Hempling.** In Michigan and in California, Mr. Chairman, utility ownership of PURPA facilities has created a regulatory nightmare, but at least PURPA investment is limited to certain plant technologies and plant sizes.

By eliminating the PURPA limits on utility ownership, the bill permits self-dealing on a grand scale. To make matters worse, the bill directly eliminates existing Holding Company Act protections against self-dealing.

Thirdly, utilities can use their affiliates to evade their legal obligation to dedicate the lowest cost power to captive customers. I give a technical explanation of that problem in my submitted testimony.

Fourthly, as Mr. Gray pointed out, utilities can use corporate form, the so-called GENCO-DISCO restructuring to preempt state law in this time of uncertainty over the future of that law.

Construction contractors as entrants to the market can own utilities they supply, thereby sitting on both sides of the table when negotiating for contract services to a utility.

In conclusion, Mr. Chairman, some have suggested that the fair competition espoused by consumer interests is but a subset, along with Senate Bill 406, of more competition. I respectfully disagree.

Senate bill 406 authorizes monopolization. Monopolization is a stage, a temporary competitive rivalry between the utilities seeking removal of all entry checks and utilities seeking maintenance of all entry barriers. The only significant dispute between those two utility groups is over which utilities will be left when the rivalry ends.

Senate bill 406 is neither incremental nor minimalist. Utilities supporting changes to the act argue that the issues of transmission, state-Federal relations and anti-competitive abuse are too contentious for Congress to handle. Mr. Chairman, freeing utilities to create affiliates to avoid state regulation will be contentious. Freeing utilities to create affiliates and offer those affiliates preferential transmission access will be contentious. In the minds of consumers, both industrial and residential, small competitors, many utilities and others, there is no quick fix to the industry debate.

I again commend you for your leadership in this debate and look forward to the questions.

[The prepared statement of Mr. Hempling follows:]

TESTIMONY OF SCOTT HEMPLING
ATTORNEY

ENERGY PROJECT
ENVIRONMENTAL ACTION FOUNDATION

BEFORE THE

COMMITTEE ON ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE

ON

AMENDING THE PUBLIC UTILITY HOLDING COMPANY ACT

"THE COMPETITIVE WHOLESALE ELECTRIC ENERGY ACT OF 1989"
(AMENDMENT NO. 267 TO S. 406)

November 16, 1989

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APPENDIX: CASE STUDIES ON UTILITY-AFFILIATE ABUSE

Mr. Chairman and Members of the Committee:

My name is Scott Hempling. I am attorney for the Energy Project of Environmental Action Foundation ("EAF"). EAF is a nonprofit, research and education organization concerned with energy and environmental issues. I have represented consumer interests in electric industry restructuring litigation, including many of the recent major industry initiatives. In particular, I have participated in 8 proceedings under the Public Utility Holding Company Act of 1935 ("PUHCA" or "the Act"), including one case recently decided by the U.S. Court of Appeals for the D.C. Circuit, and another one pending in the U.S. Court of Appeals for the Ninth Circuit. I also have written several articles on the Act and on other aspects of the electric industry, and have addressed many industry organizations on aspects of the industry's future.

I commend the Chairman for his leadership in initiating this historic debate on the Act and its role in a changing industry. I appreciate this opportunity to participate in that debate and, in particular, to analyze the implications for consumers of S. 406.

INTRODUCTION AND SUMMARY

In evaluating both the status quo and any proposal for structural change, four goals are paramount:

1. Prevent utilities with monopolies over distribution or transmission from competing unfairly against independent companies in newly developing markets for generation, conservation and load management.
2. Prevent traditional retail monopolies from using corporate structure to deprive state regulators of

their historic authority to guide utility construction and purchasing practices.

3. Prevent retail monopolies from using corporate structure to avoid their historic duty to serve captive customers at competitive, lowest feasible prices.

4. Encourage entry into the market of those entities who will bring new skills and technology into wholesale markets, and who will compete fairly over the long term.

S. 406 is not consistent with these goals. The bill would repeal the core of the Act. It would permit (1) existing utilities with distribution or transmission monopolies, (2) large construction contractors (*e.g.*, Bechtel, Westinghouse, *et al.*) and (3) "true independents," to create or acquire wholesale generation affiliates without advance SEC review under PUHCA. The proposal offers no protections to replace those it repeals.

The bill would have many adverse impacts, which may be summarized as follows: *First*, by authorizing unrestrained participation in generating markets by affiliates of utility monopolies, it would lead to unfair competition. Exacerbating this harm are two related factors: the absence of a national transmission access policy, and the proposal's failure to condition utility acquisitions of affiliates on nondiscriminatory access to the acquirer's bottleneck transmission facilities. *Second*, by permitting utilities to create generating affiliates to sell electricity back to the original utilities (*i.e.*, self-dealing), it would permit utility shareholders to siphon off efficiencies owed to customers. *Third*, by permitting utilities to "forum-shop," it would deprive states of their historic authority to protect captive retail customers. S. 406 would enact the largest structural change in this industry in 50 years.

My testimony has six parts.

Part I explains recent industry trends -- positive and negative -- so that the reader may understand the effect of S. 406 on those trends.

Part II describes the Act: its essential elements and its role today in protecting consumers, competition and regulatory effectiveness.

Part III, which represents the bulk of this testimony, presents a summary and critique of S. 406.

Part IV explains that the debate over PUHCA is a debate over utility expansion, and cannot be separated from the debate over nondiscriminatory transmission access.

Part V sets forth my responses to the specific arguments of those seeking to weaken the Act.

Part VI presents the outlines of an alternative to maximize fair competition and consumer welfare in the electric industry.

The Appendix presents several current and recent case studies of utility-affiliate abuse, which should inform our judgment as to whether to offer utilities greater latitude in creating affiliates.

I. THE CONSUMER STAKE IN THE CHANGING ELECTRIC INDUSTRY: FAIR COMPETITION, CONSUMER PROTECTION AND REGULATORY EFFECTIVENESS

To understand the reasons for, and effects of, S. 406, one must review the recent developments in the industry. We have had positive developments, such as more competition and more "least cost planning." We have had negative developments, such as corporate restructuring at a pace unprecedented since the 1930s, utility efforts to monopolize power sources and transmission facilities, and new forms of regulatory evasion. After describing these developments, I explain the special stake of the captive retail consumer in the emergence of wholesale competition.

A. Positive Developments in Regulation and the Marketplace: Competition and Least Cost Planning

1. New technologies, and new economies of scale, permit entry by small independent entities and nonprofit systems into wholesale markets. In the past decade, the electric industry has experienced an economic sea change. The traditional utility had a retail monopoly franchise. With some notable exceptions, [1] that utility was self-sufficient: building, owning and operating its own power plants. Utility purchases from others were limited to "coordination" or "pooling" transactions such as economy exchanges, capacity swaps and replacement power during plant shutdowns. Electric distribution was a franchised, monopoly

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[1] For example, regional power pools of unaffiliated utilities such as NEPOOL, and of affiliated utilities such as the American Electric Power system.

sector, and many major transmission arteries remain controlled by traditional utilities. The same conditions in distribution and transmission remain today.

But changes in the economics and technology of generation have spawned new types of generators and generating entities. These new "independents" bring new skills and technology to the marketplace. They raise and risk their own capital, unassisted by ownership of a distribution or transmission monopoly. The potential for competition in the generating sector is immense. This competition can benefit consumers directly by creating new sources of low-cost power, and indirectly by disciplining retail monopolies to keep costs at competitive levels, or face regulatory prudence disallowances.

2. State commissions are insisting that franchised, monopoly utilities build, or purchase from, the most efficient source of generation or conservation. Responding to the huge construction cost overruns of the 1970s and 1980s, utility regulators have disallowed rate increase requests that reflect imprudent or uneconomic investment. Hoping to prevent those construction errors from recurring, these regulators are experimenting with forms of competitive bidding and least cost planning designed to identify and encourage the most efficient methods of electric generation, conservation or load management. And after the U.S. Supreme Court decision in Duquesne Power and Light v. Barasch, No. 87-1160, 57 U.S.L.W. 4083 (1989), they can continue to protect ratepayers by assigning plant construction

risks to the shareholders who incur those risks.

3. Over the past 15 years, numerous bulk power players have begun to buy and sell electricity, and pool their resources over vast transmission distances without physical difficulty. Examples include the New England Power Pool, the Pacific Intertie and Georgia. This development, which has not come without significant and continuing struggle, has led to increased competition and increased efficiency. This development also has led to a common understanding, among conscientious transmission and power supply planners, that while the physical responsibility for transmission and pooling may rest in only one hand at any one time, the contractual responsibilities and economic benefits can be distributed among dozens of entities without mishap.

4. Competition stimulated by nonprofit entities continues. Competition in the electric industry is not new. It did not spring from "independent power producers" or PURPA "qualifying facilities." Competition is as old as the industry itself. Municipal power systems and rural electric cooperatives, who compete with, and purchase from, the investor-owned utilities, have brought competition to the industry since its beginnings. These systems' nonprofit status, and their accountability to voting citizens, has created yardstick by which investor-owned utilities have been judged. These same entities have faced, and faced down, the toughest anticompetitive practices from the investor-owned utilities. The results of these struggles have left legal landmarks that now benefit all new entrants to the

industry. See, e.g., Gulf States Utilities Co. v. FPC, 411 U.S. 747 (1973); Gainesville Utilities Dept. v. Florida Power Corp., 402 U.S. 515 (1971); Otter Tail Power Co. v. United States, 410 U.S. 366 (1973). Any proposed changes to the industry must ensure that there is neither continuation nor repetition of the historical discrimination against these entities.

B. Negative Developments in Regulation and the Marketplace: Corporate Restructuring, Monopolization and Regulatory Evasion

1. To minimize their market and regulatory risks, traditional utilities have turned to corporate restructuring. Today's traditional utilities are on the defensive. They no longer enjoy the certainty of rising demand, rising revenues and rising profits of the 1950s and 1960s. Instead, they face market and regulatory pressures from at least four sources: regulatory prudence disallowances; customer conservation; competition from existing market participants, such as municipal systems and rural cooperatives; and competition from new generation entrepreneurs, such as PURPA "qualifying facilities" and "true independents."

The goals underlying this restructuring have fallen into four major categories: (1) reducing state regulatory oversight of future plant construction; (2) siphoning to shareholders efficiency savings due to ratepayers; (3) competing unfairly against "true independents;" and (4) diversifying into nonutility enterprises. I discuss the specifics of corporate restructuring in my critique of S. 406 (Part III below).

2. Utilities are resisting competitive pressures by

engaging in anticompetitive practices. Nonprofit systems, PURPA facilities and other independents continue to face transmission obstacles created by utilities whose excuse is physical complexity, but whose reason is economic control. Outright refusals to transmit can violate antitrust law, and can create pressure on Congress to order sharing of bottleneck transmission facilities. Utilities know this. Therefore, they have used techniques like protracted negotiations, designed to wear down resistance to discriminatory terms; rates equal to several multiples of embedded cost; and insistence on favoring affiliates over nonaffiliates in prioritizing access to the transmission facilities.

3. Utilities are challenging the right of states to insist on the lowest cost power supplies. State efforts to protect their ratepayers from excess utility investments are facing serious legal opposition at every turn. Most prominent is Middle South's (now called Entergy) successful effort to impose the costs of Grand Gulf on a set of states who had no desire to host a plant. See Mississippi Power & Light, supra. Public Service of New Hampshire, in bankruptcy because State law requires it to bear the risks of its uneconomic investment in the Seabrook plant, is proposing a restructuring expressly to avoid that State law. Utilities in Wisconsin are challenging a Public Service Commission decision requiring transmission owners to engage in least cost planning by providing nontransmission owners with the option to own transmission facilities jointly with the utilities.

4. The regulatory agencies are tolerating corporate restructuring and anticompetitive behavior. Despite five years of notices of inquiry, notices of proposed rulemakings and task forces, each of which has exposed dramatic evidence of utility monopolization of transmission, pooling and coordination arrangements and generation markets, the Federal Energy Regulatory Commission has not exercised the leadership in the electric industry necessary to make markets work fairly and efficiently. Instead, FERC has issued a series of ad hoc, "nonprecedential" rulings that keep the industry guessing. FERC, as the regulatory agency most directly responsible for policing wholesale markets, must determine what authority it has and what authority it needs. Then FERC must use the authority it has, and seek the authority it needs. [2]

5. Utilities Freed by PURPA to Own Affiliates Free of Review Under PUHCA Have Abused That Freedom. In Michigan, Consumers Power is discriminating against PURPA facilities by denying transmission and backup service on fair terms. In California, Southern California Edison is sitting on both sides

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[2] One significant exception to the is FERC's landmark decision conditioning the Utah Power & Light-PacifiCorp merger on nondiscriminatory firm transmission service. Even in that case, the FERC declared its decision to be not precedential. Moreover, in the view of some competitor and consumer interests, including my own organization, FERC blurred an otherwise clear landmark by authorizing the merged company to (1) discriminate in the offering and pricing of nonfirm transmission service and (2) deny PURPA QFs any firm transmission service, other than the very limited service required by PURPA.

of the negotiating table and overcharging itself for PURPA power.

Regulators are only beginning to discover these abuses. More detail appears in Appendix A.

C. The Retail Consumer's Stake in Fair Wholesale Competition

Fair competition at wholesale is essential to consumer welfare at retail. Congress has expressed that view from the beginning of this industry: "[T]he history of Part II of the Federal Power Act indicates an overriding policy of maintaining competition to the maximum extent possible consistent with the public interest." Otter Tail Power Co. v. United States, 410 U.S. 366, 374 (1973). To that end, the Commission must honor antitrust law and policy in Section 203 proceedings, among others. Gulf States Utilities Co. v. FPC, 411 U.S. 747 (1973); FPC v. Conway Corp., 426 U.S. 271 (1976).

The importance of fair wholesale competition for consumer welfare, and the central role of transmission access in that competition, is well-known to courts and regulators.[3] Just recently, the Wisconsin Public Service Commission found: "Having equitable [transmission] use agreements available between and among the state's utilities has the potential for stimulating efficiency benefits for all ratepayers as a result of the increased competitive supply options available for all wholesale power purchasers....The lack of a system for the equitable allocation of the use (benefits) and costs of the transmission system inevitably results in non-optimum planning...." [4]

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[3] See, e.g., Otter Tail, supra, 410 U.S. at 369-70; Conway Corp. v. FPC, 510 F.2d 1264, 1268 (D.C. Cir. 1975) (wholesale competitors "seek to maintain customer satisfaction with the quality and price of their service in order to attract new industries and to retain existing customers"); Town of Massena v. Niagara Mohawk Power Corp., 1980-2 Trade Cases para. 63,526 at p. 76,799 (1980) (competition for the retail franchise provides consumers "with their most meaningful opportunity to compare alternate price, quality and service. Indeed, at the retail service level, it is this very potential that provides an incentive for [wholesale competitors] to control costs and improve their performance in the areas that they serve."); Alabama Power Co., 13 N.R.C. 1027, 1061-62 (1981) (describing types of wholesale competition; noting that in "yardstick competition," the "existence of a potential competitor may have an effect on the actions of another distributor"); City of Groton

Wholesale competition affects retail service in at least two ways. First, every utility, even those with distribution monopolies, has the option of serving its captive load by (1) running own generators, or (2) buying at wholesale from other owners of generation (known as "off-system purchases"). The off-system purchase option exists on a short-term basis, e.g., hourly, since some utilities' generators cost less to run than others'. The option also exists on a long-term basis; e.g., a utility considering building a new generating plant may forego the project if another utility can supply the necessary electricity more cheaply.

Where off-system alternatives are available to a retail utility at a cost lower than the cost of running its own generators, the retail utility will be bound as a matter of law

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v. Connecticut Light & Power, 662 F.2d 921, 930, 934 (2d Cir. 1981). See generally Meeks, Concentration in the Electric Power Industry: The Impact of Antitrust Policy, 72 Colum. L. Rev. 64 (1972).

[4] "Findings of Fact, Conclusion of Law and Order" at p.58, Docket No. 05-EP-5 (Wisc. PSC Apr. 6, 1989).

to purchase it, for the benefit of its customers.[5] Off-system purchase alternatives act as a discipline on the distribution monopoly, thereby producing direct benefits to retail customers in the form of lower rates and better service. The utility's retail regulators will insist that the monopoly either (1) purchase from the alternative source, or (2) reduce the price of its own electricity to match the cheaper option.

Second, utilities not only buy from the wholesale market; they sell into it, both to unload temporary excess capacity and to make "economy sales" to other utilities whose fuel costs in any particular hour may be higher. A retail utility will succeed at making those sales only if its price is lower than its competitors'. In order to keep its price low, it must be efficient. The more efficient the utility is, the lower its retail rates will be. Captive retail customers of the utility thus benefit directly from the competitive pressures faced by the utility as wholesale seller.

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[5] See El Paso Natural Gas Co. v. FPC, 281 F.2d 567, 573 (5th Cir.), cert. denied, 366 U.S. 912 (1960) ("It is the obligation of all regulated public utilities to operate with all reasonable economies."); Midwestern Gas Transmission Co., 36 F.P.C. 61, 70 (1966) (public utilities are required "to utilize all available cost saving opportunities"), aff'd sub nom., Midwestern Gas Transmission Co. v. FPC, 388 F.2d 444 (7th Cir.), cert. denied, 392 U.S. 928 (1968).

II. THE PUBLIC UTILITY HOLDING COMPANY ACT IS THE ESSENTIAL STATUTORY PROTECTOR OF CONSUMERS, FAIR COMPETITION AND REGULATORY EFFECTIVENESS

A. Overview

The Public Utility Holding Company Act is an essential statutory protector of competition and consumers in the electric industry. The Act:

1. Bars utility acquisitions which monopolize new territories or new power sources, or which create risks to consumers or investors. See Section 10(b)(1), (2), (3).
2. Demands that utility acquisitions "serve the public interest by tending toward the economical and efficient development of an integrated public-utility system." See Section 10(c)(2).
3. Limits utility speculation in unrelated ventures (e.g., banks, real estate, distant utility businesses), where that speculation imposes risks on electric customers. See Sections 1(b), 11(b)(1).
4. Guards against corporate structures that make state regulation more difficult. See Section 1(b).
5. Prohibits interaffiliate transactions within registered holding company systems, except at cost. See Sections 12 and 13.
6. Requires advance SEC review of certain bond issuances of registered holding company systems. See Sections 6 and 7.

PUHCA played a central role in breaking up the large holding companies that once plagued the nation. But the problems identified above were not interred with those break-ups. These ills easily can reappear when utility expansion is motivated by anticompetitive aims, or is unrelated to economic efficiency. Therefore, the Act continues to operate today, in two major ways: through the "pre-acquisition" review, and through ongoing financial monitoring. These elements are described next.

B. Pre-Acquisition Review Protects Consumers From Restructuring Which is Anticompetitive, Uneconomical or Unduly Complicated for Later Rate Regulators

Sections 9, 10 and 11 apply before an acquisition takes place. Together, they constitute an "entry check" by which the SEC ensures that new entrants to the industry, or existing players seeking to expand, will produce benefits for the public. Section 9 describes the types of acquisitions which trigger the pre-acquisition review standards of Section 10. Specifically, Section 9(a)(1) applies to registered (*i.e.*, nonexempt) holding company systems, and requires advance approval of any acquisition of "any securities or utility assets or any other interest in any business." Section 9(a)(2) applies to everyone but registered systems, and requires advance approval where the result of the acquisition is to make the person an "affiliate" (i.e., an owner of 5% or more) of two or more public utilities. This latter rule is commonly known as the "two-bite rule."

Section 10 supplies the standards by which SEC must judge any acquisition subject to Section 9. Section 10 contains six major requirements. These are:

1. The acquisition may not "tend towards interlocking relations or the concentration of control of public-utility companies..." Section 10(b)(1).
2. The acquisition price must bear a "fair relation to the sums invested in or the earning capacity of" the property acquired. Section 10(b)(2).
3. The acquisition may not "unduly complicate the capital structure of the holding company system." Section 10(b)(3).

4. The acquisition may not be "detrimental to the public interest or the interest of investors or consumers or the proper functioning of" the holding company system. Section 10(b)(3).

5. The acquisition may not be unlawful under Section 8 (relating to combination gas-electric companies), or "detrimental to the carrying out of the provisions of" Section 11 (relating to simplification of holding company systems). Section 10(c)(1).

6. The acquisition must "serve the public interest by tending towards the economical and efficient development of an integrated public-utility system." Section 10(c)(2). This last requirement is known as the "integration" requirement.

C. Ongoing Financial Regulation, and Limits on Nonutility Investment, Protect Consumers From the Risks of Financial Instability and Cross Subsidies

In addition to reviewing utility acquisitions under Sections 9, 10 and 11 before they take place, the SEC must monitor ongoing activities of holding companies once they exist. For registered (i.e., non-exempt) holding companies, this monitoring takes four major forms: (1) advance approval of certain issuances and sales of securities (Sections 6 and 7); (2) review of interaffiliate transactions (Section 12); (3) review of services, sales and construction contracts (Section 13); and (4) financial reporting requirements. For exempt companies, SEC oversight takes place through review of annual reports filed by the companies.

Moreover, under Section 11(b)(1) a registered company may not acquire or conduct any businesses not "functionally related" to the core utility business. This provision effectively prevents multistate holding companies from investing in nonutility businesses.

D. Exemptions From "Registration" (But Not From Pre-Acquisition Review) Are Available Where the Risks of Financial Instability and Regulatory Evasion are Small

Exemptions from the ongoing regulation provisions are available under certain circumstances. The most common exemption is the so-called "predominantly intrastate" exemption of Section 3(a)(1). That provision permits SEC to exempt a holding company from some or all of the ongoing regulation provisions if

> such holding company, and every subsidiary company thereof which is a public-utility company from which such holding company derives, directly or indirectly, any material part of its income, are predominantly intrastate in character and carry on their business substantially in a single State in which such holding company and every such subsidiary company thereof are organized....

A corporation which satisfies the technical requirements of a statutory exemption is not automatically entitled to it. The SEC may deny or revoke any exemption which is "detrimental to the public interest or the interest of investors or consumers." Section 3(a).

Exemptions apply only to the ongoing regulation provisions. No one is exempt from the pre-acquisition review provisions of Sections 9 and 10.

To Summarize: During this period of rapid corporate change, PUHCA provides essential protection by subjecting restructuring to a pre-acquisition check. That check preserves fair competition, consumer protection and regulatory effectiveness.

III. S. 406, BY ELIMINATING PUHCA'S ADVANCE REVIEW OF ENTRANTS INTO WHOLESALE MARKETS, LEAVES COMPETITION, CONSUMERS AND REGULATION EXPOSED TO UNFAIR UTILITY PRACTICES

A. Summary of the Proposal: Acquisition or Creation of Utility Affiliates Would Take Place Free of PUHCA's Pre-Acquisition Review

The proposal creates a class of entities called "exempt wholesale generators ("EWG"). With certain minor exceptions, acquisitions of EWGs would take place free of any review under PUHCA.

1. Definition of "Exempt Wholesale Generators"

a. An EWG is a person engaged directly, or indirectly through an affiliate, "exclusively in the business of owning or operating all or part of one or more eligible facilities and selling electric energy at wholesale." Section 2(a)(1). [6]

b. An "eligible facility" is an electric generating facility, or a portion of such facility, "used for the generation of electric energy exclusively for sale at wholesale (including inter-connecting transmission facilities necessary to effect such sale at wholesale)...." Section 2(a)(2).

2. In General, Acquisition of EWGs Would Take Place Free of Any PUHCA Review

The bill states that an EWG will not be considered an "electric utility company" under Section 2(a)(3) of PUHCA, and "shall be exempt from all provisions of" PUHCA. Section 2(b). As a result, an acquisition would take place, with certain exceptions, free of review under PUHCA. For example:

a. A non-utility corporation or wealthy person may create or acquire an unlimited number of EWGs, in any part of the country, without any SEC review under PUHCA. Examples: construction contractors like Bechtel or Westinghouse; coal companies like Consolidated Coal; oil companies like Exxon; Wall

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[6] All "Section" references are to sections of the proposal, unless otherwise noted. Terms used in the bill have the same definitions as in PUHCA.

Street brokerages like Kidder Peabody or Drexel Lambert; individual financiers like Carl Icahn.

b. An existing utility company may create or acquire an unlimited number of EWGs, in any part of the country, without any SEC review under PUHCA. Examples: PEPCO, SDG&E.

c. An existing "exempt" utility holding company (i.e., exempt under Section 3 of PUHCA) [7] may create or acquire an unlimited number of EWGs, in any part of the country, without any SEC review under PUHCA. Examples: Sierra Pacific Resources, Southern California Edison, Consumers Power.

d. An existing "registered" utility holding company may create or acquire an unlimited number of EWGs, in any part of the country, without any SEC review under PUHCA. Examples: American Electric Power, Middle South (recently renamed Entergy). These registered companies would remain subject to PUHCA for certain types of transactions, including: (1) the issuance of securities by the registered holding company for purposes of financing the acquisition of the EWG; (2) the guarantee of the EWG's securities by the registered holding company; and (3) service, sales or construction contracts between the EWG and the registered holding company.

3. Exceptions to the "No Advance Review" Rule

a. SEC consent required: Consider an affiliate of a registered holding company, which affiliate exists as of the date of enactment. That affiliate may not become an EWG unless the SEC consents. (The proposal does not indicate what criteria the SEC must use in determining whether to grant consent.) Section 2(a)(1). Example: NEPCO, an affiliate of NEES which currently owns generation used to sell power at wholesale, could not become an EWG without advance consent from SEC.

b. State consent required (sometimes): Consider a facility for which "a rate or charge for, or in connection with, the construction of [the] facility, or for electric energy produced by [the] facility (other than any portion of a rate or charge which represents recovery of the cost of a wholesale rate or charge) was in effect under the laws of any state" at the time of enactment. Section 2(a)(3). That type of facility could not be transferred to an EWG without special consent by each state commission "having jurisdiction over such rate or charge." Id.

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[7] Public utility holding companies commonly are classified as either "exempt" or "registered." A "registered" holding company must comply with all of the Act's requirements, including the ongoing financial monitoring requirements of Sections 6, 7 and 13; as well as the diversification restrictions of Section 11. If the holding company satisfies one of the five tests set forth in Section 3 of the Act (e.g., the company is "predominantly intrastate"), the Commission must exempt it from the ongoing financial monitoring requirements, unless the exemption would be detrimental to "the public interest or the interest of investors or consumers." Section 3(a). Both exempt and registered holding companies must comply with the pre-acquisition review requirements of Sections 9 and 10.

(1) Example of state consent required: For the simple example requiring state consent, consider a utility, PEPCO, which owns a plant and uses that plant to make retail sales in Maryland and the District of Columbia. The utility wishes to transfer all or part of the plant to a new EWG, which would sell the output at wholesale. The utility must obtain the consent of the Maryland and D.C. commissions before making the transfer. However, there would be no SEC review under PUHCA.

(2) But -- state consent AND SEC consent avoided: Now consider a plant owned by Montana Power, and used by that utility for retail sales. Assume part of the plant constitutes excess capacity. Assume further that the Montana PSC has disallowed 35% of the plant from rate base. This 35% portion would be deemed to be a "facility" (since the term "facility" includes portions of a facility, Section 2(a)(2)). There would be no "rate or charge for ... [this] facility ... in effect under the laws of the state." Therefore, the utility owning the entire facility could transfer title to the 35% portion to an EWG without state consent (and without advance SEC review under PUHCA).

(3) State consent AND SEC consent avoided again: Consider Grand Gulf, which is owned by a wholesale generating subsidiary (not a retail operating subsidiary) of Middle South (now called Entergy). Mississippi Power & Light (MP&L) buys Grand Gulf energy from the generating subsidiary under a wholesale rate. MP&L's retail rate, to the extent it reflects Grand Gulf costs, is a "rate ... which represents recovery of the cost of a wholesale rate...." Therefore, Middle South could transfer Grand Gulf to an affiliated EWG without obtaining state consent. Section 2(a)(3). And provided the affiliate receiving the plant did not exist on the date of enactment, SEC consent would not be required either. See Section 2(a)(1).

B. Overview of the Problem: The Utilities are Using the Rhetoric of "Competition" to Disguise Their Plan to Weaken Competition

As I explained in Part I, many utilities want to restructure to dilute state regulation, compete unfairly against "true independents," and siphon efficiency savings from ratepayers to shareholders. But these restructuring plans are substantially blocked or inhibited by the Act. Consequently, the utilities want the Act eliminated. Instead of candid calls for repeal, utilities create corporate constructs and "exempt" them from the Act. Utilities don't expand; they create "independent power producers" or "exempt wholesale generators." A utility affiliate cannot be an "independent" without being an oxymoron, an "independent affiliate." Independent of what? When a utility with a distribution or transmission monopoly creates, finances, owns and controls another company, there is no independence.

Any reasoned debate over the future of the electric industry must distinguish meticulously between two types of entities: (1) entities financed, owned and controlled by utilities with monopolies over distribution or transmission markets; and (2) "true independents;" i.e., those entrepreneurs who raise and risk their own capital, unassisted by a distribution or transmission monopoly.

Nevertheless, S. 406 creates an artificial category, "exempt wholesale generators," sweeps both kinds of entities into it, and exempts them from every provision of the Act. These corporations could enter the market anywhere, acquire as many wholesale utilities they desire, and face no advance review under PUHCA.

The question presented by S. 406 is not whether we should encourage more competition in generation markets. Everyone agrees with that proposition, except some utilities fearful of that competition. In Part VI below, I suggest targeted amendments to PUHCA to accomplish that purpose. The real question presented by S. 406 is this:

> Should we permit electric utilities with monopoly retail franchises or monopolies over strategic transmission facilities (or both) to create or acquire power supply subsidiaries, without advance federal review of the implications for consumers, competition, efficiency or state regulation?

For the nine reasons set forth below, the answer is "no."

C. Nine Fundamental Changes in Utility Accountability

1. Utilities Can Use Their Affiliates to Discriminate Against Competitors in Power Purchases and Transmission Access

The alternative energy and small power production sector has brought unprecedented levels of competition to the industry. That sector is filled with small entities that succeed by means of skill and efficiency, not wealth. They raise and risk their own capital, unassisted by ownership of a retail monopoly.

Traditional utilities who once looked askance at these efforts are now seeking to replicate them. At least three dozen utilities are pursuing such independent power projects across the country. For example, Pacific Gas & Electric has formed a joint venture with Bechtel Power Corp. to develop such projects. Eastern Utility Associates, a registered holding company, has created two independent power subsidiaries; they are involved in managing, operating or financing alternative energy projects. One of Southern California Edison's Mission Energy subsidiaries had 700 MW of alternative energy capacity on line by the end of 1987.

S. 406 permits unrestrained participation by affiliates of retail and transmission monopolies in that sector. The utility owner may discourage competitive small power production by favoring its affiliated projects. This favoritism can take place in at least three ways. First, the utility may make its obligatory PURPA purchases from affiliated qualifying facilities before contracting with nonaffiliated ones. Since a utility's avoided costs diminish as it contracts with additional qualifying facilities, this tactic would assign the lowest avoided cost payments to the nonaffiliates. Second, the utility may impose on nonaffiliates unusually burdensome reliability standards or other contract terms. Third, the utility could furnish design and engineering assistance to its affiliates at bargain basement prices, while denying such assistance to nonaffiliates. It may be impossible for regulators to detect such discrimination.

A special case of the favoritism problem concerns fair access to bottleneck transmission facilities. Transmission facilities are the highways of commerce in the electric industry. Competition in generation will not exist unless competing sellers cannot move their products to market, or if buyers cannot access the least expensive product. The major "bottleneck" facilities are owned by investor-owned companies with retail monopoly franchises.

S. 406 ignores this fact of life. Freed from PUHCA's restraints on unlimited expansion, utilities can (1) create affiliates to serve distant markets, (2) grant preferential transmission access to the affiliates, and thereby (3) prevent others from competing in those markets. Utilities have practiced this type of discrimination for years.

PUHCA amendment and transmission access are linked, inseparably, by the reality of this industry. For a more detailed discussion on this topic, see Part IV below.

2. Utilities Can Use Their Affiliates to Evade The Legal Obligation to Dedicate the Lowest-Cost Power to Captive Customers

a. Utility Purchases From Affiliates, For the Purpose of Serving Captive Customers, are Fundamentally Inconsistent With the Utility's Obligation to Serve at Least Feasible Cost

Assume a new low-cost generation opportunity appears. The parent utility with the retail monopoly should exploit this opportunity for its customers. Instead, the utility channels the opportunity to its affiliate. The affiliate then produces the low-cost power, and sells to the parent utility at the parent's higher avoided cost. Captive retail customers would pay that marked-up price. In effect, the utility would have diverted savings from captive customers to shareholders. That behavior violates the monopoly franchise obligation.

The parent utility also would have violated principles of fair competition. In a free market, competition would push the retail price down to the level of the most efficient seller's production cost. But in the case of a franchised utility, where there is no competition at retail, the price remains at the utility's avoided cost. The difference is monopoly rent. Prices reflecting monopoly rent are inefficient, legally exploitative, and violative of antitrust law.

b. Utility Affiliates Can Become Instruments of Self-Dealing

Abusive self-dealing occurs when the customers of the monopoly utility pay a supramarket price for a service or good supplied by an affiliate because there was no unaffiliated competitor to provide the service or good. Conversely, abusive self-dealing occurs when the utility transfers assets or provides services to the affiliate at a below-market price.

The utility affiliate relationships spawned by PURPA have led to serious self-dealing abuses, as Appendix A shows. S. 406 would expand the potential for self-dealing dramatically, in at least two ways. First, S. 406 permits on a grand scale the self-dealing permitted by PURPA. By authorizing utilities to form affiliates without limit and without advance review, S. 406 permits innumerable additional opportunities for the types of transactions described in the Appendix.

Second, S. 406 directly eliminates existing protections against self-dealing. Under S. 406, an "exempt wholesale generator" is deemed not to be an "electric utility" under PUHCA. A utility can therefore acquire unlimited numbers of EWGs in many states. Under PUHCA today, a holding company with wholesale utility subsidiaries spread across several states would be a registered holding company, like Entergy or American Electric Power. Under today's Act, a registered holding company would be subject to the interaffiliate transaction monitoring under Sections 13, 14 and 15 of the Act. But since the entity owning

EWGs would not be a registered holding company (it would not be a "holding company" at all because it owns no "electric utility"), the entity would not be subject to Sections 13, 14 and 15. In short, an entity whose self-dealing would be monitored under today's Act would not be monitored under S. 406. The difference is stark.

3. Utilities Can Use Corporate Form to Preempt State Law and Regulation

In the 1970's, utilities' initiated large capacity expansion programs, based on projections of high demand and moderate construction costs. These projections turned out to be wrong. Consequently, state regulators in the 1980's excluded a substantial amount of utilities' construction investment from retail rates. Disappointed with this treatment, utilities now seek to minimize future state regulatory scrutiny. One strategy is to shift regulatory review from states to the Federal Energy Regulatory Commission ("FERC"). To accomplish this, utilities must (1) create generating affiliates and (2) successfully apply the developing constitutional doctrine of preemption.

The preemption doctrine, utilities argue, operates as follows: Assume Selling Utility contracts to sell power to Buying Utility. Assume further that FERC, the regulator of wholesale interstate transactions, approves the contract as "just and reasonable" under the Federal Power Act. Buying Utility then requests permission from the state commission to raise retail rates to reflect the cost of its purchase from Selling Utility. Utilities argue that the preemption doctrine bars the state commission from denying Buying Utility's request on grounds that Selling Utility's price was based on excessive costs or otherwise unfair. FERC's approval of Selling Utility's rate, they argue, preempts the state commission from reaching a contrary conclusion.

And what role can corporate restructuring play in shifting regulatory oversight from states to FERC? The traditional utility generates and distributes electricity through a single corporation. Only one sale takes place: the retail sale, regulated by the state commission. But suppose the utility places its generation and distribution functions in separate corporations, "GENCO" and "DISCO," respectively. GENCO would sell its electricity to DISCO, which in turn would sell to consumers. The first sale would be a wholesale transaction, regulated by FERC. And under utilities' view of the preemption doctrine, FERC's approval of that transaction would bind the state commission when DISCO seeks a rate increase reflecting its purchase from GENCO. Before restructuring, the state would review generation costs; after restructuring, FERC would review generation costs.

In effect, the availability of the GENCO-DISCO restructuring option allows a utility to engage in "forum shopping," replacing state regulation with FERC regulation, at the utility's option. The result is a significant loss of regulatory accountability. A federal commission regulating hundreds of utilities necessarily will pay less attention to a particular utility's plans and expenditures than will a state commission with long-term responsibility for regulating a handful of utilities. The state regulators and their permanent staffs simply will know their local utilities better. Moreover, citizen comprehension of, and participation in, the regulatory process is stronger when the forum and the decisionmakers are close to home.

In Mississippi Power & Light v. State of Mississippi, 108 S.Ct. 2428 (1988), the U.S. Supreme Court held that FERC's allocation of power plant construction capacity among the utility subsidiaries of a centrally planned holding company preempts state commission review of the utility subsidiaries' decision to participate in that construction. The decision places the future of state regulation in doubt. This doubt applies to such innovations as least cost planning and competitive bidding for new generation, as well as the more traditional prudence reviews.

The law in this area is very uncertain and still developing. Federal legislation may be necessary to clarify the states' future role. Until that clarification occurs, any proposal to ease the creation of utility affiliates by repealing PUHCA is risky.

We cannot let entities enter markets on the assumption that the regulatory process will protect consumers and competition, when no one knows what regulatory process exists.

4. Utilities Can Shift Valuable Resources and Management from Markets Where They Have the Exclusive Franchise to Markets Where They do not Have the Exclusive Franchise

From the perspective of captive retail customers, utility expansion into new markets raises the same problems as does utility diversification in general: risk of failure, diversion of utility profits from measures which would strengthen the utility's financial condition, reduced utility maintenance, the "draining" of top management from the core utility, and cross-subsidization.

A company cannot argue, simultaneously, that (1) it has resources and management skills that can benefit other territories, and (2) that it is retaining its best resources and management for the local utility business. Managers cannot be in two places at the same time. These two arguments can be consistent only where the utility has excess resources or excess management. And if the utility has excess, the utility can always transfer this capacity to a new company and spin off that company to its shareholders. There is no public interest reason why the utility need retain control of the new company. In this way, the public will receive the benefits of the excess skills and assets, but will not face the risk that the utility will use those skills and assets in an anticompetitive manner, using its monopoly franchise as a base to expand.

5. The Restructuring Permitted by S. 406 Can Lead the Nation Away from Environmentally Protective Power Supply Alternatives

"Qualifying facilities" under the Public Utility Regulatory Policies Act of 1978 (PURPA) tend to be smaller, cleaner and more efficient than traditional "central station" plants. Repeal of PUHCA would give a boost to non-QF options that are quicker to build, easier to finance, larger and less clean.

For example, under S. 406 an EWG need not own an entire facility, and the entire facility need not be devoted to wholesale generation. Therefore a utility could build a large coal or nuclear plant, use what electricity it needs for the captive customers, and sell the rest at wholesale through the EWG. There would be less incentive to build small plants that now qualify for PURPA.

PURPA facilities would face competitive disadvantages in competing for distant markets. Utilities owning transmission would give access preference to their non-PURPA EWG affiliates, while barring QFs from the transmission lines. An analogy: PacifiCorp, upon its merger with Utah Power & Light, received FERC authorization to exclude QFs completely from transmission service.

6. Utilities Can Acquire Their Competitors Without Advance Review

Under S. 406, a franchised monopoly could acquire a competing independent generating company, without advance SEC review as to whether the acquisition was anticompetitive. At a time of increased utility interest in acquisitions (e.g., PacifiCorp's merger with Utah Power & Light, and Southern California Edison's proposed acquisition of San Diego Gas & Electric), it is unwise to eliminate any acquisition oversight.

7. Construction Contractors Can Own The Utilities They Supply, Thereby Sitting on Both Sides of the Table When Negotiating for Major Construction Goods and Services

Construction contractor consortiums pose a major threat to competition. The generating entity selects contractors based in part on their ability to purchase a share of, and absorb the risks of, the venture. For a utility to select its contractors based not on skill or cost, but on their ability to finance their own self-interested expansion plans, is questionable business practice. Furthermore, the practice of forcing construction contractors to contribute equity to the project they are serving creates an entry barrier to the construction services market. The practice discourages competition from smaller, less established, but perhaps more innovative, construction firms who cannot finance large projects or absorb the inevitable risks of the power supply market.

8. Owners of Utilities Will Have Little Relationship To, or Knowledge of, Local Economic Concerns

Under S. 406, a utility in Virginia could own a utility in California. With no explanation, S. 406 sweeps away a 50-year history of local accountability and local control. PUHCA's drafters criticized such arrangements harshly, on the grounds that absentee management could not ensuring utility accountability to local concerns like economic development and consumer protection.

9. S. 406 Makes No Distinction Between the Adjustments Entrants (1) Want and (2) Need

Proponents of S. 406 complain about the "onerous" burdens of PUHCA, but they rarely cite the provisions they find bothersome. Instead, they seek full exemption from all aspects of the Act.

This approach confuses the debate, because it makes no distinction between the changes they want and the changes they need.

In the case of true independents and traditional utilities, the only possible barrier to entry is the "integration" aspect of Section 10(c)(2). Under that requirement, a holding company acquiring its second and succeeding utilities must show that the acquisition "will serve the public interest by tending toward the economical and efficient development of an integrated public-utility system." In layperson's terms, a holding company may not own more than one utility corporation unless all the utility assets operate together as a single integrated, coordinated system. A holding company may not own a utility subsidiary in Maine and a utility subsidiary in California; the two utilities never could act as a single coordinated system.[8]

Nothing else in PUHCA prevents a utility or an independent from owning as many utilities as it desires, provided the owner can satisfy the standards of Section 10(b), which protect consumers, competition, and the effectiveness of regulation. These standards increase the public scrutiny of entrants, but they do not bar entrants. Entities lacking plans or ability to abuse consumers, competition or the regulatory process have nothing to fear from these tests. Even if Congress had to relax Section 10(c)(2) to remove the "integration" requirement, it need not relax the protective standards of Section 10(b).

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[8] It is not even clear that this requirement is a bar rather than a burden; it is a bar only if the entrant requires each project to be placed in a separate subsidiary. I will accept this point for the purposes of argument, but it remains to be proven. Those who seek radical changes to the Act certainly must do more than say that "Wall Street" requires those changes.

Moreover, Congress can eliminate the integration requirement of Section 10(c)(2) without relaxing the improvement requirement. It is one thing to eliminate the coordination requirement, on the grounds that true independents should be able to inject their talent and entrepreneurship in distinct regions, without having to make each project coordinate with another. It is quite another thing to eliminate the "improvement" requirement. The improvement requirement is necessary to ensure that a single holding company does merely expand for the sake of expansion; but that it expands because expansion improves the lot of ratepayers. Again, there is no need to eliminate this commonsense improvement requirement at the same time one eliminates the integration requirement.

D. Conclusion: The Debate is not Between "Competition" and "No Competition;" But Between "Fair Competition" And "Unfair Competition"

Proponents of S. 406 have termed consumer opponents as opponents of competition. Their reasoning: (1) PUHCA substantially bars utilities and construction contractors from creating generation subsidiaries to sell in wholesale markets. (2) The PUHCA barriers guarantee a future of vertically integrated monopolies. (3) Protectors of PUHCA, therefore, are protectors of vertically integrated monopolies and enemies of competition.

This analysis implies that the electricity debate is a debate over two worlds: "competition," represented by utilities supporting S. 406; and "no competition," represented by the utilities opposing S. 406. That viewpoint rests on a false dichotomy. There are in fact three worlds: "no competition," "unfair competition" and "fair competition." S. 406, by freeing utilities to expand without review for anticompetitive purpose of effect, represents "unfair competition."

The S. 406 proponents also confuse two concepts: "competitors" and "competition." They seek to eliminate PUHCA in order to eliminate entry barriers to certain competitors. This change, he claims, will increase competition. But admitting competitors is different from increasing competition. If the new competitors compete unfairly, they will reduce competition. By analogy: The antitrust laws restrain competitors. But repeal of those restraints hardly would assure competition.

Some also have suggested that the "fair competition" espoused by consumer interest is but a subset, along with S. 406, of "more competition." They are wrong. S. 406 authorizes monopolization. S. 406 therefore represents a stage, a temporary competitive rivalry, between utilities espousing removal of all entry checks, and utilities espousing maintenance of all entry barriers. The only significant dispute between these two utility groups is over which utilities will be left when the rivalry ends.

Finally, some utilities argue that issues of transmission, state-federal relations and anticompetitive abuse are too contentious for Congress to address; Congress, therefore, should take the "narrow" approach of repealing PUHCA. But repealing any of PUHCA's essential consumer protections will be contentious. Freeing utilities to create affiliates to avoid state regulation jurisdiction will be contentious. Freeing utilities to create affiliates, and to offer those affiliates preferential transmission treatment denied to others, will be contentious. Any effort to give utility monopolies more freedom to abuse their monopolies will be contentious. There is no way separate these issues, and there is no "quick fix" to this debate.

PUHCA's central purpose is to prevent utilities from creating affiliates as a means to extend their market power. Exempting utility-owned subsidiaries from the Act is indistinct from repealing the Act.

IV. THE DEBATE OVER THE DESIRABILITY OF UTILITY EXPANSION CANNOT BE SEPARATED FROM THE DEBATE OVER NONDISCRIMINATORY TRANSMISSION ACCESS

The question on the relationship between PUHCA and transmission is simple: Should electric monopolies be free to buy and sell in wholesale markets, while using their control of essential transmission facilities to deny that same freedom to others? We believe the answer is "no."

A. Nondiscriminatory Transmission Access is Essential to Fair Competition and Efficient Utility Operations

1. Transmission facilities are monopoly facilities: In the electric industry, transmission facilities connect generating

plants with local distribution systems. Most long distance transmission facilities are "essential" or "bottleneck" facilities: because of construction costs and state siting restrictions, no alternative paths exist. Therefore whoever controls the transmission highways controls who can buy and sell electricity. The situation is no different from one in which Farmer A and Farmer B compete to sell wheat, and Farmer A controls the only road connecting both farms to the food processors.

The transmission world is divided into "haves" and "have nots." The "haves" are large utilities. The "have nots" are small utilities, customer-owned systems (municipals and rural electric cooperatives), cogenerators and other "small power producers," and "independent power producers."

2. Utilities have used their control of transmission to weaken competition: Failure to mandate nondiscriminatory transmission access has distorted bulk power markets. FERC Commissioner Stalon recently stated (April 1989 APPA meetings) that the existing transmission situation was "not sustainable." He also has declared (February 1989 NARUC meetings):

> The incentives for utility managers to use control of transmission facilities to foreclose competition to protect large utility investments in an increasingly competitive generation sector may be strong. They may far outweigh whatever incentives exist or can be created to expand and open up transmission in order to serve bulk power markets.

In a similar vein, FERC's Transmission Task Force found (pp. 67-68) that "examples of the use of monopoly power to limit competition are abundant."

3. Nondiscriminatory transmission access promises higher efficiencies and lower electric prices: At any point in time, each generating plant in a region operates at a different cost. These cost differentials result from differences in fuel prices, plant efficiencies, labor costs, maintenance schedules and even weather. With nondiscriminatory transmission access, each utility can buy the least expensive power in the region during any particular hour. Nondiscriminatory transmission access guarantees that at any point in time, the region's most efficient generators are operating. For example, the recent FERC Transmission Task Force Report found (p.67): "Large cost differentials between regions in the past suggest that utilities have sufficient market power to protect their franchised service areas....Market power that can protect the franchise ... can also stifle competition in areas where competition is the preferred economic arrangement."

4. Nondiscriminatory transmission access avoids unnecessary power plant construction: Suppose Utility X knows it needs an additional 100 MW of generating capacity in 1995, 200 MW in 1997, and 300 MW in 2000. Without transmission access, Utility X must build a 300 MW plant by 1995, and let most of the capacity sit idle for five years. That would be inefficient. With transmission access, Utility X has two alternatives which are far more efficient: (1) Utility X could buy available capacity from other utilities for the first four years, then bring on the new

plant in 2000, when the full capacity 300 MW is necessary. (2) Utility X could bring on the full 300 MW in 1995, but sell the unneeded capacity to others for the first four years.

5. Nondiscriminatory transmission access promises cleaner air: Utility X uses coal plants. During a particular hour, Producer Y may have cleaner power. With transmission access, Utility X can buy less coal by buying from Producer Y.

B. Calls for Transmission Access are Coming from All Corners of the Industry

FERC's Transmission Task Force Report declared:

> Transmission or the lack thereof can be a barrier to entry in the emerging competitive portion [the generating portion] of this industry....Independent power producers, QFs [i.e., "qualifying facilities" under PURPA], and state-sponsored bidding procedures will create a need for transmission access policies that ensure owners of generating plants that transmission service will be available when needed.

FERC heads a very long list of interests calling for transmission access. Among them:

Wall Street financiers have told generation entrepreneurs that new plants cannot be financed with assurance of fairly priced transmission service.

Gas companies like ENRON, with direct knowledge of the success of nondiscriminatory gas transportation, have called for similar policies in the electric industry.

Intensive electricity users like Dow Chemical and General Motors, who must compete against companies from nations which do have nondiscriminatory access, want to ensure that their local utilities have access to the lowest source of power.

Entrepreneurial generators, such as cogenerators and budding "independent power producers," have called for transmission access because they cannot enter the market without it.

Consumer-owned power systems, such municipals and rural electric cooperatives, want transmission access to avoid overdependency on monopoly utilities for power supply. The century-old competition between consumer-owned and investor-owned utilities has benefited all consumers as each type of entity disciplines the other to keep costs down and quality of service high.

Federal power marketing agencies like the Southeastern Power Administration (SEPA) need transmission access to ensure that low-cost hydroelectric power gets to the communities to which Congress allocated that power. Indeed, SEPA has sued Kentucky Utilities, once before federal court under antitrust law and once before FERC under PURPA, because KU has refused to deliver such entitlement power to small towns and cities in Kentucky. The first lawsuit was dropped in the mid-1980s; in the second action FERC, without reaching the merits of the case, found it lacked the statutory authority to order the transmission of SEPA power.

Even some utilities, most prominently Entergy (formerly called Middle South) have said that transmission access is necessary for fair competition.

C. Nondiscriminatory Transmission Access Will Not Lower Reliability; It Will Increase Reliability by More Power Supply Options

Utilities argue that offering transmission access to others is too complicated. They are wrong. The Office of Technology Assessment of the U.S. Congress recently found that there were "no technical impediments" to wholesale transmission access as means to enhance competition. Wheeling and Dealing: Technological Considerations for Increasing Competition (OTA May 1989).

But the best answer to the utilities' argument lies not in a government report, but in the industry itself. Over 20 years, a steady march toward transmission access has occurred without mishap. Since the early 1970s, the electric industry has moved inexorably toward greater transmission access. The 1970 amendments to the Atomic Energy Act obligated the NRC to require certain nuclear plant licensees to offer nondiscriminatory transmission access and power pooling to competitors. The 1973 Otter Tail decision in the U.S. Supreme Court enjoined the utility from refusing transmission service to a captive municipal utility. Otter Tail Power Co. v. United States, 410 U.S. 366 (1973). In the mid to late 1970s, newly formed "joint action" agencies of municipal systems negotiated nondiscriminatory access arrangements with utilities in Georgia, Indiana, Minnesota and the Missouri Basin. In 1978, Congress passed PURPA, which obligated utilities to buy power from cogenerators and certain small power producers, or transmit that power elsewhere. In 1988, FERC approved the merger of Utah Power & Light and PacifiCorp, but required the companies to offer nondiscriminatory access.

D. "Voluntary" Transmission Access Is Not Working; The Progress on Transmission Access Has Flowed From Court and Agency Orders

Many utilities support "voluntary" transmission access. Under this proposal, utilities will provide transmission service when they want to; not when others need it. This option enables transmission owners to discriminate in favor of friends -- such as utility affiliates -- and against competitors. "Voluntary" transmission access is voluntary for the transmission "haves," but involuntary for the transmission "have nots." The result is discriminatory access.

Utilities, with some exceptions, have not offered nondiscriminatory access voluntarily. As noted above, progress in transmission always has required mandates from the NRC, FERC, courts and Congress.

Repealing PUHCA in the name of more competition is counterintuitive. Unleashing existing utility monopolies to speculate on new power supplies will lead to more concentration, not more competition. A more reliable approach to maximizing competition is to permit the entities that now exist, as well as new entrants into generation markets, nondiscriminatory access to these essential facilities. The surest path to more competition is not to weaken PUHCA, but to ensure nondiscriminatory wholesale transmission access.

V. RESPONSES TO ARGUMENTS OF THOSE SEEKING A WEAKENING OF THE ACT

A. Post-Acquisition Rate Review Does Not Substitute for Advance Protections for Competition and Consumers

Proponents of repealing the protections of PUHCA argue that no advance review of utility acquisitions in necessary; later review of power supply transactions will suffice to ferret out abuse. Distilled to its essence, the argument is as follows: There is no need to prevent abuses in advance, because we can discover and correct them later. The argument is not persuasive, for at least five reasons.

1. Simple logic. Utility-affiliate relations make self-dealing abuse more lucrative, and detection of that abuse less likely. The purpose of pre-acquisition protections is to prevent abuses which are difficult to detect. To eliminate those protections against undetectable abuse on the grounds that we will detect the abuses later misses the point completely.

2. The real world. The process of detection and correction is enormously long, expensive and unreliable. We are not writing on a blank slate here. Since enactment of PURPA, utilities have made substantial investments in qualifying facilities. The regulatory experience with these investments is depressing. The Appendix to my Testimony describes in detail (although vastly more detail is available) the frustration, costs and ineffectiveness of after-the-fact rate review. Litigation over the abuses by Consumers Power and Southern California Edison are years in the making, torturous, characterized by every dilatory tactic available, and still unresolved.

The extensiveness of state commission review in these cases might lead one to conclude that "the system is working." The system is not working. Only the largest states, like California and Michigan, have the commission resources to begin, let alone conclude successfully, a multi-million dollar investigation. Regulators are not catching all the abuses, on time or at all, under the present system. The record in both these cases produces the inescapable conclusion that advance review of the corporate arrangements would have obviated countless litigation hours and ratepayer loss. S. 406 will multiply the number of utility affiliates without limit, creating that many more opportunities for undetectable abuse.

To prevent abuses, regulators must anticipate them. If abuses are creative, they are harder to anticipate. To assume that utilities will never think of a scheme that regulators have not thought is to ignore the history of regulated industries. Regulation almost always is catching up with schemes designed to avoid regulation; it rarely has been the other way around.

The "after-the-fact" tool is cumbersome, inefficient and unreliable. It also is unfair to ratepayers. Ratepayers are entitled to fair rates in every monthly bill; not excess rates for three years, followed by refunds. Ratepayers are not lenders to shareholders.

3. Inconsistency. There is irony in the utilities' support for "after-the-fact" review of corporate structure. Utility after utility, including utilities testifying before this Committee last week, have scored state regulators for their "after-the-fact" review of the prudence of power plant

construction. Let us put aside the fact that prudence review of construction practices cannot logically take place before the construction itself does. Let us also put aside the fact that it was utilities, not regulators, that pressed for approval of large power plant construction in the 1970's, and resisted intervenor efforts during the construction period to reevaluate those initial approvals. Finally, let us put aside the fact that post-investment prudence review is as old as regulation itself, and that no utilities complained about that review until it produced disallowances. The point is that utilities cannot oppose one type of review on the sole grounds that it is "after-the-fact," and then oppose another type of review on the sole grounds that it is not "after-the-fact." Those two arguments are logically inconsistent. They add up to the following position: the only proper review is no review. And in a rapidly changing industry, that position is unacceptable.

4. By the time rate review takes place, irreparable damage to competition, consumers and efficiency will have occurred. Many things happen between the time a corporation is formed and acquired, and the time a power supply agreement is put into place. The shell corporation does not necessarily sit within the corporate structure, inactive. The parent transfers cash, land and other assets to it. The parent loans money to it, borrows money on its behalf, or guarantees its debt. The parent transfers management, trade secrets, business contacts and other valuable know-how to it. Several years can pass before there is

an actual power supply transaction for rate regulators to review. But during those years, the shell can maneuver itself into a position of market prominence, _before_ it signs a single power supply contract. By buying up scarce land and power resources, reaching informal agreements with top construction contractors, arranging informally preferred access to its utility affiliate's transmission system, this "shell" can eliminate its competitors before the competitors even emerge. An "after-the-fact" rate review of the power supply agreement will be confirmation of a _fait accompli_; and, to make matters worse, there will be no competitive benchmarks around to test the reasonableness of the contract terms.

The longer the behind-the-scenes maneuvering goes on, the more established the "shell" will be, to the detriment of its competitors, when the time for rate review finally arrives.

5. _Power supply contracts are not the only source of abuse_. The enforcement strategy of S. 406's proponents, reliance on later review of the power supply contract, assumes that the only harm from abuse is harm done in executing that contract. That assumption is incorrect. Operations under the contract can prejudice captive customers of the buying utility (_e.g._, diverting maintenance resources to the affiliate's operations) or to competition (_e.g._, by discriminating against nonaffiliates in the day-by-day decisions over access to the parent utility's transmission system). If these abuses are not prevented through advance corporate structure review, and are not prevented by

review of executed power sales contract, when will they be prevented?

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The debate over whether consumers receive adequate protection from rate review alone is as old as the Act itself. As the Act's Senate sponsor declared:

> It is perfectly absurd to say that [holding companies] can be regulated [after the fact]....If a holding company says "We furnished legal services to the Florida Light & Power Co., and we charged the Florida Light & Power Co. $100,000 for those services," how is any commission going to say that those personal services were worth only $10,000 instead of $100,000? When a holding company furnishes engineering services which are of personal character, how is the Commission going to regulate those services? It cannot be done, because the value of the services cannot be regulated.

79 Cong. Rec. 8391-92 (May 29, 1935). More colloquially, but no less accurately, another Senator said: "We might just as well pass a law here that a rattlesnake could not bite in the summertime as to pass a law that a holding company can exist for time after time, and continue any kind of practice, subject to any kind of regulation." 79 Cong. Rec. 9051 (June 11, 1935). As the Supreme Court concluded about the Act, after reviewing Congressional deliberations: "These [holding company] structures in and of themselves have been found by Congress to constitute an evil that cannot be met by simply regulating future transactions." North American Co. v. SEC, 327 U.S. 686, 710 (1946).

In 54 years, much about the electric industry has changed. What has not changed is the incentive for utilities to avoid or weaken scrutiny.

B. State Statutes Do Not Provide Sufficient Pre-Acquisition Review

Proponents of S. 406 have argued that States can apply their own pre-acquisition review. This is an argument for repealing the minimum standards set by the federal Act, on the grounds that States will fill the regulatory gap. Since these proponents are the same who say pre-acquisition review is unnecessary to begin with (see above), the argument itself rings hollow. Nor does it stand up well to analysis.

Utility corporate structure is not a single State problem. The utilities whose structure or restructuring has raised complex issues of multistate regulation in the last three years alone have become synonymous with industry restructuring itself: Middle South (allocation of construction cost overruns affecting four States and six regulatory jurisdictions); American Electric Power (allocation of system transmission costs, and of coal plant costs affecting seven States and eight regulatory jurisdictions); Public Service of New Hampshire (proposed acquisition by two-state holding company of a bankrupt utility in a third state, with resulting control of transmission facilities affecting as many as 5 States); Sierra Pacific (acquisition of 2000 MW power supply consortium to serve all Western States); PacifiCorp (merger with Utah Power & Light affecting seven States and eight regulatory jurisdictions; company now bidding to acquire Arizona Public Service).

These cases do involve local and State matters like power supply planning and least cost options. But they also have involved inherently interstate matters: access to long distance transmission lines, access to financing from interstate sources, and fairness of cost allocations among customers in different States, to name a few.

The list grows larger on removal of the Act's integration standards. Assume Virginia Power proposes to acquire a subsidiary in California to sell to Southern California Edison ("SCE"). We must protect the interests of captive customers in Virginia, captive customers in California, competition in Virginia and competition in California. No regulatory structure currently exists to ensure such protection without duplication or gaps.

Many States have not enacted statutes anticipating the imagination of utility corporate planners, or the complexity of future interstate transactions. Nor do they plan to, because the minimum standards in the federal Act have served all States well. States do remain free to enact structural standards more stringent than the federal Act. See Baltimore Gas & Electric Co. v. Heintz, 760 F.2d 1408 (4th Cir. 1985). But few have done so.

Corporate complexity aside, it is unrealistic to assume that the utility industry will stand by as each State enacts replicas of the Public Utility Holding Company Act. It is more likely that utilities, free of the minimum standards of the Act, will set up new corporate structures before States have new statutes in place. Nor will the industry compliantly follow 50 different sets of standards and procedures. More likely, utilities will resist enactment and application of a statute in State X on the grounds that it conflicts with a statute in State Y.

Even more likely, utilities will "forum shop" among the States, promising the economic development from new power plant construction in return for favorable regulatory treatment; or, in some cases, simply building the plant in the State with the least oversight. That activity will be no different from today's FERC-State forum-shopping. Without a minimum federal standard, such as the standard set by the Act, the operating standard may be no standard at all.

C. Utilities Cannot Tell Congress to Leave Transmission to FERC, While Telling FERC That Congress Has Kept Transmission From FERC

Freeing utilities to expand into other markets on the grounds of competition, without assuring the fairness of that competition, is inconsistent. Nondiscriminatory access to the transmission highways is essential to competition. See Part IV above. Therefore legislation authorizing utility expansion must include provisions assuring full nondiscriminatory access in all markets.

Few utilities any longer deny that some type of transmission access is necessary to promote or protect competition in the electric industry. Public Service of Indiana and Entergy are only the most recent converts to the logic that competition without transmission is not competition. The same theme echoes regularly from Wall Street, which will not finance new wholesale generation projects without assurance that the products can get to market. FERC's recent Task Force report said it as well. As explained in Part IV above, calls for transmission access are coming from all corners of this industry.

Yet utilities resist any effort to lodge, unambiguously, the duty to order such access in any governmental entity. They say that the issue is too "contentious" for Congress. They are confusing the issues, intentionally. The issue is not what the precise rates or rules for access should be. Those issues do belong before an administrative agency subject to judicial review and Congressional monitoring.

Utilities who benefit from the status quo of transmission control tell Congress that FERC should solve the problems growing out of that control. Then they argue to FERC that Congress has denied them the tools necessary to do so. The positions are not consistent. As Exhibit A in the gallery of utility opposition to FERC authority over transmission, I offer the example of the Utah Power & Light-PacifiCorp merger. Under Section 203 of the Federal Power Act, FERC was obligated to disapprove the merger unless the merger was "consistent with the public interest." The Administrative Law Judge, and FERC, found that the merger was not "consistent with the public interest," due to the merged company's control of essential regional transmission facilities. The ALJ rejected the merger. FERC approved the merger, but only if the merged company provided firm transmission on a nondiscriminatory basis. FERC did not "order" transmission access; FERC merely stated the terms which the merged company would have to accept if it wished to proceed with its voluntary merger. It was the merged company's decision whether to merge and accept the terms, or not.

Even though FERC did not order transmission access, its decision created a firestorm of protest from dozens of utilities, led by Southern California Edison, who asserted that FERC lacked the statutory authority to condition the merger on any transmission. See Electric Utility Week, Dec. 5, 1988.

The legal areas outside Section 203 are vast. And outside the context of Section 203, FERC's reading of Court decisions and its own reading of legislative history, all of which were necessitated by utility refusals to deliver power, have left it gun shy on the issue of its authority. For example:

1. In Richmond Power & Light v. FERC, 574 F.2d 610 (D.C. Cir. 1978), the Court found that where a utility transmitted for one customer but refused to transmit for another, FERC lacked authority to order the utility to expand its wheeling service to include the second customer. In other words, FERC did not have the authority to preclude the monopoly owner of an essential transmission facility to offer access to some but deny it others. But that is precisely the type of discrimination that PUHCA-freed utilities could practice.

2. In Southeastern Power Administration v. Kentucky Utilities, 25 F.E.R.C. para. 61,204 at p.61,532 (1983), FERC found that PURPA did not give it the authority to order transmission to prevent KU's anticompetitive refusal to deliver inexpensive hydroelectric power to municipal customers in Kentucky. After a detailed examination of the legislative history of PURPA, FERC concluded that to correct this anticompetitive situation would "alter competitive relationships," a result expressly forbidden by the language of PURPA.

The debate over FERC's duty to order transmission access has outlived its usefulness. Utilities would have the transmission debate disappear down a jurisdictional "black hole" between Congress and FERC. If FERC does not have the duty, Congress must order it if Congress wants competition. If FERC does have the duty, utilities should have no objection to confirming this duty, and preventing endless litigation, by enacting clear legislative language.

The only question is whether Congress will implement this agreement by granting FERC the clear and sensible authority to regulate these essential facilities. The solution to the problem takes only a handful of words, the enactment of which would take us a vast distance towards resolving the inconsistencies between what utilities say to Congress, and what they say to FERC. I offer one effort now:

> FERC shall order each owner of transmission facilities to offer transmission services on terms which are nondiscriminatory, just and reasonable, to any wholesale purchaser or wholesale seller of electricity in interstate commerce, where the failure of the owner to offer such transmission services is unjust or unreasonable, discriminatory or anticompetitive.

Some additional language would be necessary to give guidance on, and prevent future litigation over, the meaning of the terms "unjust or unreasonable, discriminatory or anticompetitive" in the context of transmission pricing and access; to give FERC an initial period of time during which it would assess each transmission owner's market position to determine if existing practices are unjust, unreasonable, discriminatory or anticompetitive; and to provide a complaint procedure by which refusals to offer transmission services could be resolved expeditiously and inexpensively, before irreparable harm to competition occurred.

Until Congress adopts this handful of words, lawyers will be paid to write, and the courts and regulators will be doomed to read, not handfuls but hundreds of briefs on the issue of FERC's authority to order wheeling.

D. The Consumer Critique of S. 406 Does Not "Rest on An Assumption of Market Pricing"

According to proponents of S. 406, the consumer critique is flawed because it assumes that post-S. 406 electric prices will be set by the market, not by regulators. They rely this false syllogism:

1. Utilities can abuse their monopoly status only when they can set prices free of regulation.
2. Nothing in S. 406 changes the current scheme for price regulation.
3. Therefore, S. 406 cannot lead to abuse of monopoly status.

The syllogism is wrong because the first step is wrong. As I have explained throughout this testimony, utility-affiliate abuse is taking place today, under traditional price regulation, simply because utilities use their affiliates to avoid price regulation, by transferring power supply responsibilities to their affiliates and buying the power back from those affiliates at higher than normal prices. The Appendix gives examples in great detail. Moreover, traditional price regulation is only as good as the information underlying it. Even where the utilities themselves produce the power under traditional price regulation, they can use their affiliates to provide services at prices higher than prudent cost, and then lock the data that would expose this abuse in the affiliate, beyond the reach of the utility's regulators.

E. The Act Does Not "Encourage Self-Dealing"

Utilities argue that the Act encourages self-dealing and therefore is anti-consumer. This is a serious misconstruction. The Act discourages self-dealing for profit, because self-dealing for profit is identical to siphoning benefits away from shareholders. Thus Sections 13, 14 and 15 create a scheme under which registered holding companies must price their interaffiliate transactions at cost.

The Act encourages -- in fact it insists upon -- integration of the assets of affiliated companies. The Act says if a utility wants to expand by acquiring or creating a new company, the assets of the acquired and existing companies must operate together in an efficient manner. In other words, the Act does not tolerate acquisitions of utility subsidiaries unless the subsidiaries act together efficiently as a single system. For those efficiencies to exist, the separate corporate entities must interact. That interaction is not "self-dealing" in the classic sense of one entity sitting on both sides of the negotiating table to divert profits.

The same utilities that urge weakening of the Act are the utilities who want self-dealing. A utility who acquires a subsidiary to build plants to sell power back to the utility knows that acquisition is not creating any efficiencies. Any efficiencies come from the new plant, which the utility could easily build itself, without a subsidiary. The utility creates the subsidiary so it can buy the power at from the subsidiary at the utility's avoided cost rather than the subsidiary's cost. That is self-dealing for a profit; the profit being the savings which belong to the ratepayers. That is precisely the type of self-dealing which S. 406 encourages.

F. S. 406 is Neither "Incremental" Nor "Minimalist" Nor "Rifle Shot;" It Authorizes a Fundamental Restructuring of the Industry

Some utilities have described S. 406 as "minimalist," "incremental" or "rifle shot" approach to the industry. The reality is otherwise. An incremental approach would let small new entrants, lacking in market power, enter the market subject to existing protections for consumers and competition. We then could assess the impact of these new entrants on efficiency, reliability and coordination. Should that approach prove beneficial to the public interest, we might consider letting larger players with potential market power into new markets, again subject to existing protections. Then we could assess the efficacy (or the necessity) of those protections.

There is nothing "incremental" or "minimalist" about S. 406. The bill authorizes entry to everyone, small and large, with and without market power, and simultaneously removes crucial protections. New entrants who never have sold electricity could enter any market without review of their financial strength under

PUHCA; existing utility monopolies could grow without limit and without advance review under PUHCA; and construction contractors could build and own the same projects, anywhere in the country and without advance review. S. 406 is the most dramatic weakening of electric utility regulation since the 1920s.

Utilities seeking entry into the wholesale markets are on the horns of a dilemma. If these markets are fully competitive, there will be winners and losers. That is where competitive discipline comes from: the ability to win, and the fear of loss. There is no reason to assume that all the winners will be utilities, and all the losers will be nonutilities. Therefore, there will be utility losses, sometimes large ones. And if the markets are not fully competitive, *i.e.*, there is a market bias favoring utilities such that utilities do not face the risk of loss, then the entire premise for weakening the Act -- adding competition -- is false.

VI. TOWARD A SOLUTION TO THE CHALLENGE OF COMPETITION

A. Introduction: Goals to Further and Interests to Protect

We must ensure that both the structure and rules for electricity markets ensure fair competition, consumer protection and regulatory effectiveness. As I explained in Part I.A of this testimony, any evaluation of proposals to restructure the industry must satisfy four policy goals. To repeat:

1. Prevent utilities with monopolies over distribution or transmission from competing unfairly against independent companies in newly developing markets for generation, conservation and load-management.

2. Prevent traditional retail monopolies from using corporate structure to deprive state regulators of their historic authority to guide utility construction and purchasing practices.
3. Prevent retail monopolies from using corporate structure to avoid their historic duty to serve captive customers at competitive, lowest feasible prices.
4. Encourage entry into the market of those entities who will bring new skills and technology into wholesale markets, and who will compete fairly over the long term.

At every point in our deliberations, we also must remain aware of four distinct interests:

1. Captive customers (wholesale and retail) of utilities purchasing power at wholesale
2. Captive customers (retail and wholesale) of the utility selling at wholesale
3. Competition (in terms of both existing market participants and future market participants)
4. Regulators (federal and state)

We cannot let entities enter markets on the assumption that the regulatory process will protect consumers and competition, when no one knows what regulatory rules will apply. Therefore, I try to set forth below, in broad terms, the rules which must apply to maximize both competition and consumer protection.

B. A Word on Methodology

A clear policy for the electric industry must answer each of the following five questions:

1. What Types of Entities Should Participate in Wholesale Markets?
2. For Each Type of Entity, What are the Existing Impediments to Entry or to Even-Handed Participation in Wholesale Markets?

3. For Each Type of Entity, Is There a De Minimis Percentage Ownership In A Wholesale Generator, Below Which No Regulatory Review is Necessary to Protect Competition, Consumers and Regulatory Effectiveness?

4. For Each Type of Entity, Is There a Maximum Percentage Ownership In A Wholesale Generator, Above Which Ownership Should be Prohibited to Protect Competition, Consumers and Regulatory Effectiveness?

5. For the Band of Ownership Between the De Minimis and Maximum Levels, What Specific Regulatory Review or Conditions Should Apply to Each Type of Entity to Protect Competition, Consumers and Regulatory Effectiveness?

A detailed answer to each of these questions is beyond the scope of this testimony. As a starting point, however, I set forth below eight general principles.

C. Outline of a Proposal

1. Entities Seeking to Enter Wholesale Markets Must Demonstrate, In Advance, Their Permanent Inability to Obtain or Exercise Market Influence

The entities seeking entry into wholesale markets range from small companies engaged exclusively in wholesale generation, to multinational construction services firms like Westinghouse and Bechtel. Each type of entity has features that offer benefits and risks to competition and the consumer. PUHCA guarantees a "fitness check" at the front door, to ensure that the entrant has no anticompetitive potential and, if it does, to condition that entry to ensure that potential is never used. This advance review and conditioning -- performed in public with participation by consumers, competitors and state regulators -- must remain a feature in our statutes.

2. Congress Should Consider A Carefully Targeted Adjustment to the Act's "Integration" Requirement

The primary flaw in S. 406 is to treat all entrants the same; and specifically, to treat utilities and true independents the same. As explained above, weakening PUHCA with respect to utility-affiliate relationships is a radical step that increases consumer risk while producing with no measurable consumer benefits.

But treatment of "true independents" is another matter. Some "true independents" make a reasonable argument that PUHCA unnecessarily discourages certain corporate structures that could lead to least cost electricity production. Specifically, they argue that the financial community insists that where a single corporation wishes to create and operate separate power projects in different locations, each project should be placed in a separate subsidiary. If the corporation takes this step, it becomes a "holding company" under PUHCA. And if the projects are located in different states (as may be the case where the original corporation has a strong national reputation for building, owning and operating cost-effective, environmentally responsible projects), the Section 3(a)(1) "intrastate" exemption from PUHCA's ongoing regulation requirement is not available. Absent some change in PUHCA, these entities will be discouraged from bringing their skills and investment dollars to new markets. [9]

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[9] As of today, many of these entities have placed qualifying facilities in the separate subsidiaries. Under PURPA, the qualifying facilities are not subject to PUHCA. The problem occurs when these entities seek to develop projects other than

If the true independents' arguments are eventually shown to have factual support, I believe Congress should consider adjustments to PUHCA that would permit such entities to set up generating subsidiaries in different states free of most of PUHCA's ongoing regulation requirements. These are the entities best able to increase competitiveness in the generating sector. Unlike utility affiliates, the true independents can compete in these new markets without risking the well-being of captive customers, because they have no captive customers. If their financing requirements make the subsidiary form the most efficient operating mechanism, Congress should adjust PUHCA to make this possible. Before doing so, however, we must learn more about the financing process, to assure that the subsidiary form for true independents is both necessary and efficient.

It is not clear that true independents require, or should have, complete exemption from all ongoing financial review, however. Consumers, as well as the entire local economy served by a true independent, have a strong interest in the short-term and long-term financial viability of electric producers. Some of the PUHCA's ongoing regulation assures such viability. It may be that PUHCA's financial criteria need some adjustment to reflect the special risks, and special protections, existing in today's financial world. Moreover, it may be that entities other than the SEC could or should exercise the required financial oversight. I would be pleased to work with other participants in

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qualifying facilities.

this debate, to identify the relevant financial concerns and design a means for resolving them.

Moreover, pre-acquisition review for anticompetitive impacts must remain intact. Although acquisitions by utilities with distribution or transmission monopolies carry more anticompetitive potential than acquisitions by true independents, the latter category is not without risk. Over time, some independents may, through acquisitions, obtain market power over generation in certain regions, even though they lack distribution or transmission monopolies. For that reason, acquisitions by true independents should remain subject to the "concentration of control" review imposed by Section 10 of the Act. Where a proposed acquisition contains no threat of concentration, this review process will be uneventful. But where there is the possibility of market power, the review process will provide an opportunity for the applicant, consumers and regulators to work out protective conditions.

3. Existing Utilities Should Not be Permitted to Expand From Their Base as Retail and Transmission Monopolists Until Congress Verifies Their Inability to Compete Unfairly

Existing utilities are not new entrants. They are existing players, protected by monopolies over distribution or transmission, hoping to expand their influence.

These utilities assert they can bring skills and resources to markets outside their monopoly service areas. If so, there is no reason why they cannot "spin off" those assets (assuming their captive customers are left whole) into an independent corporation to compete in new markets. This complete corporate separation between the monopoly portion of a business and the nonmonopoly portion is the only reliable antidote to anticompetitive practices and risk imposition on captive customers; yet it responds to utilities assertions that they have skills and resources to spare.

The only argument against the spin-off option is that the original utility could not itself profit from these new ventures. That is precisely the point. The utility cannot serve two sets of customers, one captive and one competitive, without creating risks of abuse that currently are insoluble. There is no public policy reason why _existing utilities_, as distinct from _independent entities_, must profit in wholesale markets. Existing utilities already have monopolies in retail markets, have had them for 50 years, and will have them for the foreseeable future. Any challenger to that retail monopoly faces formidable financial and political obstacles. Existing utilities have little cause for dissatisfaction.

My position has this premise: we do not have regulatory tools which reliably can prevent abuse by one entity with two personalities -- monopoly and competitive. We cannot authorize monopoly utility expansion, and then hope those tools develop. But when those tools develop, this question is worth reviewing. In particular, nondiscriminatory wholesale transmission access -- which would permit a wholesale customer fearing abuse from one supplier to shop for another -- will take us a long distance toward development of the necessary regulatory tools.

It should go without saying that utilities cannot be permitted to form affiliates which sell power to those utilities. That is not utility expansion, but utility siphoning. Such corporate shuffling would be consistent with consumer protection only if the electricity sales price from the affiliate to the utility was the lowest of the following: (1) the affiliate's prudent cost (including reasonable return); (2) the cost the utility would have incurred had it build the project itself; or (3) the price produced in a fully competitive market.

4. FERC Must Have the Authority and the Duty to Order Nondiscriminatory Transmission Access, On Behalf of Both Existing and New Participants in Wholesale Markets, Where Necessary to Promote or Protect the Forces of Competition

I discussed this matter fully in Part V.C.

5. Competitors, Consumers and Regulators Must Have Expedited Access to Regulatory Procedures and Protections if the Conditions Warranting Initial Entry Change Adversely

Given FERC's hesitance to declare its authority to order transmission where necessary to protect or promote competition, the victim of utility discrimination has only one alternative, at least where the requested transmission service affects interstate commerce: filing a lawsuit under the antitrust laws in federal district court.

This is not a realistic alternative for most existing market players; it is less realistic for new players who cannot raise money until they get transmission access. Lawsuits on transmission access in the electric industry are so rare that they can be counted on two hands.

Protracted litigation dries up investment funds and simply rewards the entrenched utility with the cash flow to wait out the controversy. Even after FERC obtains clear authority to order transmission, there cannot be fair competition without expedited procedures to resolve transmission disputes.

6. The Relationship Between Federal Regulation and State Regulation Must be Rational, Predictable and Independent of Corporate Form

In power supply planning, every level of government is involved on some issue. To give a few examples: Siting and zoning are local. Retail rates and policies on fuel mix are statewide. Markets are regional. Transmission effects and reliability can affect national policy. The list, of course, is much longer.

Almost everyone agrees that the present allocation of responsibility does not work: it encourages forum-shopping through corporate restructuring, results in external effects from one state to another, and places control over uniquely local decisions in federal hands, and allows utilities to escape effective regulation by locking cost and transactional data in corporations outside the jurisdiction of regulators. These are but a few of the common and well-founded complaints.

Although there have been many valiant attempts, no one yet has determined how to involve each of these levels of government in a rational, predictable manner. Certainly no legislation restructuring the power supply industry can take place until these regulatory responsibility problems are solved.

7. Until Congress Chooses to Change the Statutes, SEC Must Enforce Them Vigorously

Current law must be followed. See Wisconsin's Environmental Decade v. SEC, 882 F.2d 523 (D.C. Cir. 1989) (holding that SEC's approval, in three different cases, of a holding company acquisition which made no change in utility system operations, did not comport with the integration requirement in Section 10(c)(2) of the Act).

8. Congress Must Confirm the Legal Standing of Retail and Wholesale Customers, and of Competitors, to Challenge Agency Decisions Adverse to Wholesale Competition

In two recent cases, utilities have challenged the legal standing of retail ratepayers to assert an interest in wholesale competition and in corporate restructuring. These challenges are disturbing. If a captive retail ratepayer does not have a direct, economic interest in fully competitive markets, who does? This issue was discussed in more detail in Part I.C. above.

Congress, within the limits of its constitutional authority, must make clear that the beneficiary -- or victim -- of electric utility practices and utility regulation is the consumer.

CONCLUSION

Increasing competition in the generation sector is no simple task. We must find ways to channel new funds and expertise into the effort fairly and efficiently. Simply authorizing existing retail monopolies to expand into this sector, free of advance review under PUHCA, risks loss of regulatory oversight and competitive harm; moreover, it appears to authorize utility behavior which is inconsistent with the obligation to serve at lowest feasible cost. For those reasons, S. 406 is not well-suited to the task at hand. We cannot separate the issue of entry into wholesale markets from the issues of State-federal regulatory relations, nondiscriminatory transmission access and statutory protection from anticompetitive and other monopolistic practices. To this end, I have offered the broad outlines of a policy proposal that would accomplish these ends.

I appreciate this opportunity to present my views, and congratulate this Committee and its Chairman for initiating this debate. I would be pleased to answer any questions from Members of the Committee.

APPENDIX

CASE STUDIES ON UTILITY-AFFILIATE ABUSE

APPENDIX

CASE STUDIES ON UTILITY-AFFILIATE ABUSE

S. 402 has the potential for significant harm to ratepayers and competitors because it would enable utilities to avoid PUHCA protections otherwise applicable to affiliated EWG's. Even today, examples of such abuse can be seen in situations where PUHCA's restriction have been relaxed and where utilities have been allowed to engage in self-dealing with non-integrated generation affiliates in the form of QFs.

Pursuant to PURPA sec. 602, 16 U.S.C. sec. 824a-3, and FERC's implementing regulations, 18 CFR sec. 292.602, QF's are exempt from PUHCA requirements. Electric utilities may own up to 50% of a QF. 18 CFR sec. 292.206(b). As in the case of the proposed bill under consideration by this Committee, PURPA does not restrict the utility-owned QF's dealings with its parent.

Several utilities, prime among them Southern California Edison Company and Consumers Power, have availed themselves of the opportunity presented by the PURPA loophole to participate in QFs and through that participation, to engage in self dealing. The point of such dealings is to benefit stockholders to the severe detriment of ratepayers and competitors.

Utility holding companies use a variety of strategies to increase their profits at the expense of the captive ratepayers of their utility subsidiaries. These schemes can generally be divided into three types: self-dealing transactions, cross-subsidies, and efforts to avoid regulation.

I. SELF-DEALING

Abusive self-dealing is usually the result of non-arm's length bargaining between a utility and one of its affiliates. As a result of these transactions between affiliates of the utility holding company, the customers of the utility affiliate pay a higher price for a service or product supplied by another affiliate because there was no outside competition for that service or product. What often happens was stated well by the Michigan Public Service Commission when it described an inter-affiliate contract as the utility having "once again negotiated with itself and lost."

Transactions between a utility and its non-utility affiliates are termed abusive self-dealing when:

A. the utility contracts with a non-utility affiliate to purchase property, goods, or services, and pays more for those goods, services, or property than it would in a competitive market;

B. the utility contracts to sell utility property, goods or services to a non-utility affiliate and accepts a lower-than-market-value price for the property, goods or services; or

C. the utility gives an affiliate a competitive advantage with far more favorable contract terms than it offers competitors.

II. CROSS-SUBSIDIES

Utility holding companies often use their utility affiliates to subsidize their non-utility affiliates. These subsidies can be either direct or indirect.

A. A utility affiliate may directly subsidize a non-utility affiliate when the holding company transfers some or all of the utility's profits to the non-utility affiliate. Such subsidies can lead to investor uncertainty and can adversely affect the financial reputation of the utility.

B. A utility affiliate may indirectly subsidize a non-utility affiliate by allowing its resources and personnel to be used by the non-utility affiliate. If the non-utility does not reimburse the utility for all of the associated costs (and these are often difficult to quantify), then the utility rate-payers are subsidizing the non-utility affiliate.

III. AVOIDING REGULATORY AUTHORITY

Utilities often try to avoid regulatory authority because effective regulation is what takes the place of competition. If a utility cannot avoid regulation altogether, it may search for the most sympathetic regulatory forum. When a utility is able to avoid regulation, or is able to find the most sympathetic regulator, the utility is able to retain the benefits of monopoly (lack of competition) without being hampered by the regulatory rein that protects the consumer against unfair treatment. In other words, the utility wants to have its cake and eat it too.

A. Utility holding companies use their non-utility affiliates for transactions in an attempt to evade regulatory scrutiny. If the holding company can set up a sufficiently complex corporate structure, the regulators may not be able to untangle the transactions sufficiently to protect the rate-payer.

B. Utility holding companies try to use non-utility affiliates to avoid the caps that state commissions set on profits. If a non-utility affiliate receives regulatory approval of an unfair wholesale electric rate, the state regulator may have to approve the pass-through of that rate even though the rate does not meet the state's requirements. For example, FERC allows CWIP in the rate-base; many state commissions do not.

PREVENTING UTILITY HOLDING COMPANY ABUSIVE SELF-DEALING REQUIRES STRONG STATE AND FEDERAL REGULATORY MANDATES

Below are a number of case studies of utility holding company monopoly abuses. These abuses were all discussed in state utility commission hearings. This might lead one to conclude that the system is working and there is no need for concern. However, only the largest state commissions have the resources available to conduct an extended, multi-million dollar investigation into utility holding company activities.

After-the-fact review and disallowance of imprudent costs is a cumbersome tool for utility regulators. And, given the complexity of the holding company systems, there is no guarantee that the commissions can uncover all of the abuses the utilities practice. Finally, many abuses are only uncovered after they have been underway and the consumers have been overcharged for a number of years.

This Appendix contains summaries of abuses practiced by a number of utilities and their affiliates. These utilities include Southern California Edison Company, Consumers Power Company, Florida Power Corporation, Tucson Electric Power, Sierra Pacific Power Company, Ohio Power Company, Columbia Gas System, Arizona Public Service, Niagara Mohawk Power Corporation, Central Illinois Public Service Company, Montana-Dakota Utility Company, and Public Service Company of New Mexico.

SOUTHERN CALIFORNIA EDISON COMPANY

The California Public Utility Commission's Division of Ratepayer Advocates ("DRA") has undertaken an extensive investigation of Southern California Edison Company's ("Edison") QF activities, and particularly, its contract to purchase power from Kern River Cogeneration Company ("KRCC"), a 50/50 partnership between Getty Oil Company (predecessor to Texaco Producing Company) and a wholly-owned Edison affiliate (Southern Sierra Energy Company).[1] The contract, which involves more than 200 MW of generation, is striking in terms of the manner in which it was negotiated and the results of the negotiations, as well as the anticipated equity returns (in the range of 46%-69%) to the affiliated QF.

Not only did Edison sit on both sides of the bargaining table (as is inherent in any situation in which a utility purchases power, or anything else, from an affiliate), but the Edison personnel responsible for negotiating and executing the contract with KRCC were at the same time officers, employees or consultants of Southern Sierra Energy Company or KRCC. For example, the Edison attorney responsible for reviewing the KRCC contract at Edison served as an officer of KRCC; the Edison Vice President with overall responsibility for QF purchases, who signed the KRCC contract on behalf of Edison, was then President of Southern Sierra; the manager of Edison's Department of Cogeneration and Power Department, with overall responsibility for negotiating the KRCC contract, served as Vice President and General Manager of Southern Sierra and Vice Chairman of the KRCC Management Committee; and Edison's negotiation coordinator for the KRCC contract provided consulting services to Southern Sierra in matters relating to the contract. There is not even the semblance of arm's length dealing when people are placed in the impossible position of negotiating with themselves. According to the DRA, these two-hatted Edison personnel refused to heed the concerns raised by the other Edison personnel as to the KRCC contract's deviation from the standard offers authorized by the CPUC and the potential for payments in excess of avoided cost.

Given its origins, it is no surprise that many of the contract terms favor KRCC (Edison's affiliated QF) at the expense of Edison's ratepayers. Some of the more flagrant abuses identified by the DRA include:

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[1] California Public Utilities Commission, Division of Ratepayer Advocates, Report on the Reasonableness of Southern California Edison Non-Standard Power Purchase Contracts with Qualifying Facilities, Application No. 88-02-016, December, 1988. Edison and KRCC have filed testimony opposing the DRA's findings, which have been the subject of a hearing. No decision has been issued.

1. Excessive capacity charges: Edison agreed to pay KRCC the higher capacity charge applicable to firm capacity commencing operations during 1986, rather than the lower charge applicable to projects commencing operations in 1985, even though the project was planned to commence and in fact commenced firm operations.

2. Cancellability on ninety days notice: Although Edison insisted that every standard offer require five years notice and stiff penalties for early termination of firm capacity contracts exceeding 100 MW, KRCC may terminate its contract after the first twelve years on ninety days notice if, in its opinion, the contract becomes "unprofitable at any time."

3. Cancellability without repayment of capacity overpayments: The KRCC contract provides heavily front-loaded levelized payments for twenty years of firm capacity but permits KRCC to cancel, after the first twelve years, without paying back any overpayments due to levelization. After the DRA investigation was underway, Edison attempted to cure this deviation from the standard contracts approved by the CPUC by amending the KRCC contract. Edison's belated action merely highlights the unjustifiable nature of the original "give-away".

4. Nonfirmness of the so-called firm capacity: The KRCC contract does not limit scheduled maintenance during the peak periods when Edison needs the generation the most. Yet, the contract obligates Edison to pay capacity charges as if it were a firm capacity contract. Again, after the DRA investigation was underway, Edison sought to cure this obvious problem by amending the contract to limit such scheduled outages to 30 peak hours during peak months, consistent with CPUC approved standard contracts. This belated effort to firm-up the contract in 1988, a time of excess capacity, is itself a form of self-favoritism: no other QF could do so.

In sum, the DRA concluded that the KRCC contract is a non-standard contract with payments exceeding avoided cost and with less risk to the affiliated QF (and greater risk to Edison's ratepayers) than the standard QF contracts approved by the CPUC. The DRA sought $52 million in refunds for only a three year period of operation.

More significantly for this Committee, the DRA recommended that the CPUC (1) prohibit Edison from entering into any new purchase power agreements with QF affiliates and (2) request the holding company to divest itself of any ownership interest in the QFs with which Edison now does business. As explained in the DRA report, DRA requested this relief because: "[t]his is the only way to prevent further self dealing and serious harm to Edison's ratepayers from affiliated QF transactions." (DRA Report at IV-30). An experienced Certified Public Accountant testifying on behalf of the DRA explained the basis for this relief (DRA Report at IV-26 to IV-28):

> Auditing and assessing the reasonableness for ratepayers of transactions between utilities and their corporate relations before the Commission is monumentally difficult, painful, controversial and litigious. Utility management is often forced to defend sweetheart deals made for the benefit of affiliates or holding company headquarters, thus putting utility management in a very uncomfortable position. The DRA Staff is not equipped to monitor and investigate all possible abuses in utility transactions with affiliates and headquarters. Increased diversification creates the need for more staffing devoted to investigate more and more potential areas of abuse.
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> Electric utility participation in cogeneration and in other alternative generation projects which sell electricity to the utilities presents vertical integration problems and potential for self-dealing. Utility participation in QFs is not prohibited by PURPA. However, utility participation in QFs places utilities in the awkward position of wanting to keep its avoided costs low, in order to provide the cheapest cost of service to ratepayers, and to keep avoided costs high, so its QF affiliates will be as profitable as they can. Thus two parts of a utility can be competing to provide future generation, the in-house electric department and its subsidiaries or affiliates involved in QF alternative generation projects. This creates incentives for distorted decision making within the corporation and creates mixed incentives for utility positions in Commission proceedings on what avoided cost based prices adopted by the Commission should be.

Edison's response to the DRA's request for relief was to argue that the CPUC lacks the authority to restrict Edison's dealings with and ownership of QF affiliates. Edison argued that Congress, in enacting PURPA, and FERC, in promulgating the implementing regulations, preempted the CPUC from limiting utility participation in QFs. Edison asserted that the CPUC was similarly preempted from adopting DRA's alternative relief of an "Affiliate Cost Adjustment", designed to flow through to ratepayers the excess profits Edison's QF affiliates earn above Edison's CPUC authorized return or the average return earned by similar industries. [2] In essence, Edison argues that even if the CPUC agrees with the DRA that the QF affiliate situation results in self dealing and severe harm to consumers, the CPUC cannot take the steps necessary to provide the requisite protection.

Additional Self-Dealing after 1984

Edison's use of affiliated QFs to maximize stockholder returns at the expense of ratepayers and competitors did not end with the execution of the KRCC contract in early 1984. As detailed in testimony filed at the Federal Energy Regulatory Commission in an ongoing Edison wholesale rate case, [3] in January, 1985, right after it had finalized contracts for 685 MW from affiliated QFs in December 1984, Edison sought from the CPUC an emergency ex parte interim order suspending the standard offer applicable to large cogeneration contracts due to an over capacity situation. Curiously, Edison did not join PG&E in urging suspension of these standard offers due to excess capacity in November, while Edison was finalizing the contracts with its affiliates. According to the testimony, the December, 1984 affiliated QF contracts raise self dealing problems similar to those apparent in the KRCC contract.

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[2] Concurrent Opening Brief of the Southern California Edison Company (U 338-E) Regarding the Reasonableness of Execution and Administration of the Kern River Cogeneration Company Contract, dated June 26, 1989, filed in CPUC Application No. 88-02-016, at pp. 89-99.

[3] Prepared Direct Testimony and Report (QF Issues) of Baker G. Clay on behalf of the City of Vernon, California, filed in Southern California Edison Co., Docket No. ER88-83-000 (Phase I) in March 1989. Edison has not yet filed responsive testimony.

B

CONSUMERS POWER

This case study demonstrates the attempts of a utility holding company to promote the interests of the corporate shareholders to the detriment of the customers. This case involves blatant self-dealing and efforts to ignore regulatory scrutiny.

Background

Consumers Power Company (Consumers) is a utility affiliate of a utility holding company in Michigan. In the early 1970's, Consumers began construction of a large nuclear power plant in Midland, Michigan. After a number of problems, Consumers cancelled the plant in 1984. Because Consumers had invested significant resources in the facility, the Michigan Public Service Commission (MPSC) was forced to "authorize a $99 million annual increase in Consumers' electric rates" so that Consumers could avoid bankruptcy. Re: Consumers Power Co., 66 P.U.R.4th 1, 2-3 (Mich. PSC 1985).

A holding company (CMS Energy) was formed to diversify the utility and recover its financial health. In an effort to recoup some of its investment, Consumers sold the abandoned nuclear plant to Midland Cogeneration Venture (MCV), a subsidiary of CMS Energy holding company and an affiliate of Consumers. MCV turned the plant into a 1,240-MW gas-fired cogeneration facility, intended to supply steam to Dow Chemical Company and electricity to Consumers.

On August 14, 1987, Consumers signed a contract with MCV to purchase the entire 1240 MW of power at an average capacity rate of 4.15 cents per kilowatt-hour. The contract was for 35 years. In September, 1987, MCV filed an application for approval of capacity charges in the contract with Consumers. The Michigan Public Service Commission (MPSC) ordered a determination of the avoided costs on Consumer's system, the need for capacity on Consumer's system, and the appropriate mix of suppliers to meet the projected need.

On January 31, 1989, the MPSC issued an interim order declining to approve the MCV contract. Re: Midland Cogeneration Venture Limited Partnership, Opinion and Interim Order (January 31, 1989). Instead, the Commission set the firm capacity need of Consumers from cogeneration and small power production projects at 1160 MW. The Commission directed that Consumers should contract with a variety of projects offering firm commitments, fuel diversity, long-term reliability, and prices at or below the avoided cost of 3.77 cents per kilowatt-hour in 1990. (The rate for projects fueled by natural gas was set at 25% less.) The Commission required that no more than 55% of the capacity be obtained from any one project and no more than 75% of the capacity be supplied by projects using any one fuel. In terms of the MCV project, this meant that Consumers could purchase no more than 638 MW of capacity from the project and could pay no more than 2.83 cents per kwh in 1990.

Non-arms'-length Bargaining

In its January opinion, the Commission examined the MCV contract and noted that negotiations for the MCV contract had not been part of an arms-length bargaining process. For example, the consultant who served as MCV's chief negotiator was selected by a vice-president of Consumers and was paid by Consumers. Many of the officers of MCV were officers of Consumers when the MCV was formed. One vice-president of MCV testified not only that he remained a participant in Consumers' employee benefit and retirement programs, but that his paycheck was still printed on Consumers' paper and MCV was billed for his salary. Id. at 101. The MPSC concluded that "the testimony reveals that Consumers had a dominant, controlling role in the MCV at the time of the contract negotiation." Id.

Bargaining with Other Parties

As a result of the January 31 order, Consumers renewed negotiations with other power producers. Under the terms of the negotiations, Consumers required each project to pay an administrative fee of $10,000 to participate in the negotiation process. Consumers would not allow developers to increase the size of their original projects even though the capacity rate set by the Commission made smaller projects uneconomical. Many developers complained "that the combination of the rates and terms of the agreements made them the most onerous power purchase agreements in the United States." Order of June 22, 1989, at 11. One developer said that the standard agreements contained "virtually every 'deal-breaker' Consumers could think of to prevent developers from obtaining financing: dispatch provision, off-peak variable energy cost reduction, back-up status, security for early termination, 300-day termination period if there were appeals, and waiver of claims against Consumers." Id. at 28.

Self-Dealing

The Commission criticized Consumers for self-dealing with the MCV and said:

> There is also the regrettable implication that Consumer's self-dealing is responsible for some of the shortcomings in the process. The company's discussion of its renegotiations with the MCV is instructive. In its ancillary filing, Consumers says that it was placed in the awkward position of being forced to renegotiate its power purchase agreement with the MCV. As a result, it says, it was unable to obtain all of the concessions required by the interim order. The company's theme is familiar. The interim order

> discussed the original negotiations that resulted in the MCV power purchase agreement. The Commission concluded that the record amply established that the contract did not result from arm's-length negotiations. Although details of the renegotiation of the MCV agreement are not on the record, one must wonder whether Consumers has once again negotiated with itself and lost. Order of June 22, 1989 at 30-31 (emphasis added).

Risks to the Ratepayers

The Commission also questioned Consumers' request for an additional 250 MW of MCV capacity. Noting that Consumers claimed its proposal was not designed to backstop project attrition, the MPSC nonetheless believed that the MCV capacity would be used for exactly that purpose. Further the Commission pointed out that "As a practical matter, the company's proposed approach for additional MCV capacity provides significant opportunities for the company to affect the need for that capacity in ways that are not conducive to a rational energy policy for the state. ...[T]he company's proposal is not without significant risks that ratepayers will pay for the 250 MW of additional MCV capacity, regardless of whether there are reasonable opportunities to avoid the need for that capacity. Consumer's activities to date with regard to the MCV provide no basis to believe that the company will not seek additional ways to promote the interest of the MCV. and thereby Consumers' stockholders, at the expense of its ratepayers." Id. at 38 (emphasis added).

Unjustified Capacity Forecasts

Consumers told the MPSC that it was faced with having to renegotiate a valid, enforceable power purchase agreement with the MCV in order to comply with the interim order of January 31. Raising the specter of protracted litigation and adverse consequences to the ratepayers if it had to renegotiate, Consumers sought permission to purchase an additional 250 MW of capacity from the MCV. As justification, Consumers used its capacity forecasts.

The MPSC criticized Consumers' forecast capacity need of 1,900 MW. Authorizing a capacity addition of only 1,160 MW, the MPSC noted that Consumers had based its forecast of need on a forecast of abnormally warm weather. The Commission said "It is patently absurd, for example, to use abnormally not weather as a basis for planning. Proper system planning is based on normal conditions, and a reserve margin is provided to cover abnormal weather..." June 22, 1989 order at 18.

The Commission added that:

> Consumers has still not accepted the Commission's determination of need and balancing of the

> uncertainties. It seeks a different result by its request for approval to purchase 888 MW from the MCV, rather than the 638 permitted by the interim order. ...
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> It is apparent that the company's overwhelming corporate objective is to obtain Commission approval for as much as possible of the MCV capacity now and first priority for an additional 250 MW of MCV capacity when more capacity is needed, regardless of the interest of its ratepayers and the policies embodied in PURPA. ...One can only speculate whether the company would be as eager to put itself "at risk" for the additional 250 MW of MCV capacity if it did not own a substantial interest in the MCV.
>
> ..the Commission flatly rejects any suggestion that the public interest and PURPA are well-served by a corporate policy that pursues maximum MCV capacity as its highest priority. Consumers would have this Commission approve capacity sufficient to meet Consumers' highest forecast despite the opportunity for the Commission to approve the addition of a lesser amount now and additional capacity when it is more certain that it will be needed. Consumers would have this Commission grant first priority to the MCV for the next 250 MW of capacity despite the ability of the company, probably at lower cost, to use conservation and load management to reduce demand and a reasonable amount of long-term purchases to meet increased need. Consumer would have this Commission pursue a course of action designed to prevent or limit its ratepayers from receiving the full benefits of a diverse mix of qualifying facilities, as intended by PURPA. Order of June 22, 1989 at 19-21 (emphasis added).

Different Contract Terms for Its Affiliate

As further evidence of self-dealing the MPSC noted that Consumers' proposed contracts with the other projects were substantially different from its contract with MCV. The other projects were required to implement all of the recommendations in the consulting engineer's annual inspection reports; MCV was not. The other projects were required to schedule outages to accommodate the requirement or obligations of Consumers; MCV was not. Order of June 22, 1989 at 24.

Transmission Access Denied to Non-affiliates

Additionally, the MPSC recognized that Consumers had apparently offered transmission access to the MCV project but had denied such access to other projects. Id. at 40. The Commission said "the company should know that the Commission will not permit Consumers to allow the MCV to freely use the facilities for which Consumers' ratepayers have paid in any manner that adversely affects the price or reliability of its electric supply to its ratepayers." Order of June 22, 1989 at 24.

Ex Parte Communications

Finally, the MPSC criticized Consumers for what it termed ex parte communications. Saying that Consumers had solicited public and private sector leaders to send letters and resolutions encouraging the Commission to approve Consumers' package, the MPSC said "Consumers has also set out, apparently deliberately, to encourage others to violate the spirit of the prohibition against ex parte communication." Order of June 22, 1989 at 44.

Complexity of the Process

The Michigan PSC called the Consumers' proceeding the "most complex, most controversial, and most highly contested proceeding ever heard by the Commission." Order of June 22, 1989 at 3. The hearings and pre-hearing conferences required 90 days. More than 60 parties participated and more than 100 witnesses testified. The record consists of 120 volumes of transcript, 14,383 pages, and 428 exhibits.

Refusal to Accept PSC Decision

In the June 22 Order, the MPSC refused to approve any purchase of capacity from MCV above the 638 allowed in the January 31 Opinion and Interim Order. In response, Consumers announced that it would press forward with its appeals of the PSC's orders in the Michigan courts and would honor its original contracts with the MCV. Consumers has taken the position that the MPSC only has authority to set the rate at which it can purchase power and cannot determine from whom and on what terms Consumers can purchase power. See Opinion and Interim Order (January 31, 1989) at 67-69.

Natural Gas Transactions Benefit MCV

Consumers is a combined gas and electric utility and as such sells both natural gas and electricity to its customers. The Michigan Attorney General's office analyzed Consumers' gas contracts and found that Consumers had negotiated less expensive gas contracts for MCV than for itself. Apparently the Canadian government approved gas sales for MCV only because Consumers bought addition, higher-priced gas for its gas customers.

Summary

Through its transactions with MCV, Consumers has sought to obtain at least the following benefits:

* Full recovery of approximately $1.5 billion of cancelled nuclear plant assets (which it would otherwise be forced to write off, at least in part).

* Profits from the sale of cogenerated power at above-cost rates (to itself or to others).

* Elimination of competition in the field of cogeneration and power production.

Consumers has also exposed itself--or its ratepayers--to at least the following risks:

* Disallowance by the Michigan PSC of some of its payments to MCV for purchased power.

* Inability of MCV or Consumers Power to market some of the MCV facility's output.

* The possibility that CMS Energy will be required to make payments to MCV to support MCV revenues.

FLORIDA POWER CORPORATION

A. Self-dealing in the Purchase and Transport of Coal

In February 1986, the Florida Public Service Commission (FPSC) opened a docket to investigate the affiliated cost-plus fuel supply relationships between Florida Power Corporation (Florida Power) and its affiliated fuel supply corporations. The investigation looked into the prudence of coal transactions and the selection of transportation options which bolstered affiliate revenues. On September 7, 1989, the FPSC ruled that some of the coal transactions had been imprudent and ordered an investigation of the financial cost to the ratepayer. The FPSC also ordered Florida Power to refund $5,370,000 plus interest to its customers as a result of imprudent affiliate self-dealing in coal transport.

Complexity of Corporate Structure and Transactions

The corporate structure and transactions set up by Florida Power to supply its fuel needs was so complex that the FPSC felt constrained to comment on the complexity and to examine the fuel supply and delivery network in detail. In Re: Investigation into affiliated cost-plus fuel supply relationships of Florida Power Corporation, Docket No. 860001-EI-G, Order No. 21847 (Fla. PSC September 7, 1989).

In March, 1976, Florida Power established Electric Fuels Corporation (EFC) as a wholly-owned subsidiary and signed a contract for the purchase and delivery of coal to its Crystal River plants. In 1979, EFC purchased an 80% undivided interest, including mineral and surface rights, in 33,000 acres of land in Kentucky and Virginia. This acreage was leased to the Dulcimer Land Company (Dulcimer), which is a partnership between Little Black Mountain Coal Reserves, Inc. (a wholly-owned subsidiary of EFc) and Murphy's coal Company with partnership interests of 80% and 20%, respectively. Dulcimer subleases the coal reserves to various coal producers, one of which is Powell Mountain Join Venture (PMJV). PMJV is a 50-50 partnership between Homeland Coal Company Inc. (a wholly-owned subsidiary of EFC) and Angus Minerals Company, Inc. Both Murphy's Coal Company and Angus Minerals Company are wholly-owned subsidiaries of Amvest Corporation, the company from which EFC purchased its interest in these coal reserves. A chart of this structure is attached.

The FPSC pointed out that one of the issues raised in the proceeding was whether the creation of EFC and its affiliate network had resulted in excess risk and fuel cost to Florida Power Ratepayers. While declining to decide that issue, the Commission commented on "the complexity of FPC's fuel supply structure and the inherent tension created when an unregulated affiliate must make choices which may impact either adversely on

FPC's ratepayer or the affiliate's shareholders." Opinion at 19.

In discussing its responsibility to review non-utility affiliate transactions, the FPSC said, "We also believe it important to note that EFC was created with and apparently given, conflicting goals. On the one hand, ERC is charged with acquiring the highest quality, lowest cost fuel available for FPC's ratepayers and on the other hand EFC is seeking to make a profit for its shareholders. We believe these two goals can often be at odds and incompatible. Therefore, we find it appropriate and necessary to continue to review each of EFC's transactions on behalf of FPC on a case by case basis to insure that FPC's ratepayers are protected from any adverse impact which may result from EFC's conflicting directives." Opinion at 19-20.

Non-utility Affiliate Activities

Coal transactions: The FPSC determined that EFC had not followed Commission procedures in its coal transactions on a number of occasions. "The record of this proceeding does not demonstrate that EFC followed any of the generally accepted procedures prior to the purchase of the Dulcimer reserves. ...EFC purchased Dulcimer reserves prior to the completion of the preliminary reserve estimate and the final feasibility study." Opinion at 6. In 1979 and 1980, EFC relied on telephone conversations to update the 1978 formal solicitation of the compliance coal market. The Commission said, "we believe it is appropriate for a utility to be able to produce documentation of its efforts to this commission when the company seeks to recover costs associated with the transactions from its ratepayers." Opinion at 7. Finally, the FPSC examined EFC's cost-plus contract with PMJV and concluded that the decision to enter into the PMJV contract was not reasonable or prudent considering the unstable compliance coal market which existed at the time. Opinion at 9. The FPSC reserved determination of whether the imprudent action resulted in excessive costs for ratepayers until it had established a final market standard methodology.

Among other findings of fact on this issue, the FPSC found that:

*EFC's entry into a long-term, cost-plus contract with an affiliate without a market reopener on a take-or-pay basis without a solicitation was imprudent.

*The FPC/EFC contract places the risk of PMJV price increases on FPC's ratepayers.

*The initial PMJV price was above the prices prevailing in the market.

*The profit margin in the PMJV contract is much greater than the industry average.

*PMJV earned a return on equity of 44%=56% between 1982 and 1986. This is five times the average of eleven other companies who mine coal in the same region.

*PMJV coal was not needed until 1984, but EFC began shipping PMJV coal at an earlier date.

Transportation: In March, 1977, EFC signed a partnership agreement with Dixie Bulk Transport, Inc. and created a partnership called Dixie Fuels Limited (Dixie) whose purpose was to set up an ocean-going barge system to transport coal. EFC owns 65% of Dixie. Although EFC also operated unit trains to deliver coal by rail, the FPSC stated that the evidence showed "no impediments to EFC making these improvements to their rail delivery fleet [by increasing the number of its unit trains] at an earlier date except EFC's commitment to their waterborne transportation route." Opinion at 14.

The FPSC said "we do not believe it is appropriate for a utility to favor an affiliate transportation route over a less costly non-affiliate transportation route to the detriment of its ratepayers." Opinion at 14.

Among the findings of fact on this issue, the FPSC found that:

*In 1983, EFC said that it was "not in a position to guarantee 2.4 million tons of coal per year for each remaining calendar under the contract."

*In October 1985, EFC increased the minimum tonnage commitment to 2.4 million tons per year and committed a total of four Dixie barge/tows to FPC.

*There was no economic analysis of the benefits to FPC ratepayers from EFC's reversal of position and decision to increase the tonnage commitment.

*EFC's decision increased cost and risks to ratepayers without offsetting benefits.

*Before EFC agreed to increase the tonnage commitment, it experienced significant net losses on the fourth barge. After EFC signed the agreement it experienced significant net profits on the fourth barge.

*Under the agreement, FPC ratepayers subsidize the fourth barge if it is not used in third party backhaul business.

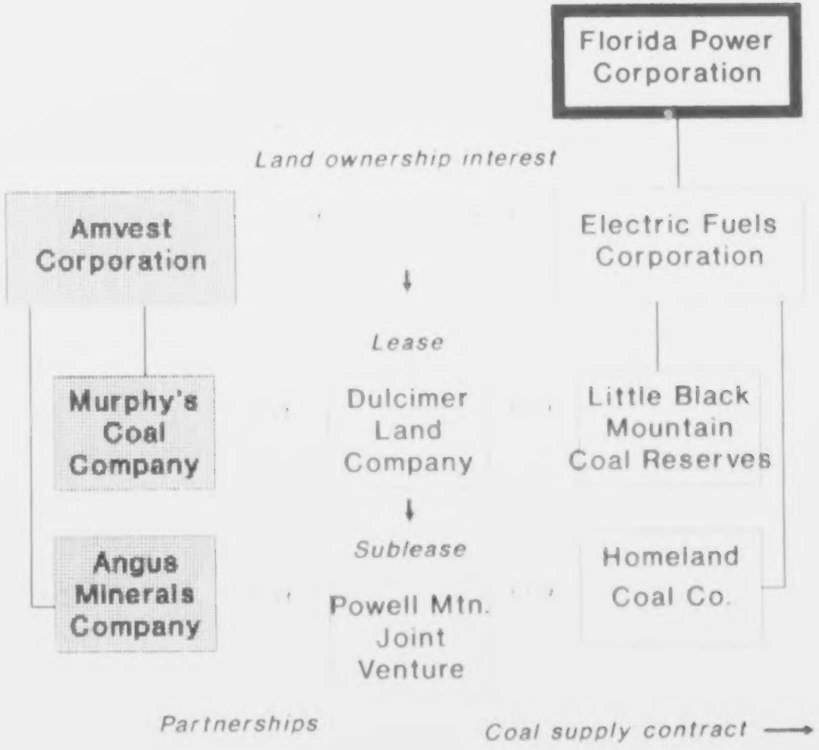
*EFC's expanded commitments to its waterborne affiliates effectively decrease leverage with the railroad because they remove those additional tons from competition.

Summary

Florida Power's fuel affiliate, EFC, has established such a complex structure and pattern of transactions that the FPSC has a difficult and time-consuming task to protect the ratepayer from abuses. Some of the transactions have been clearly imprudent and the FPSC has ordered a refund to customers when the imprudence has resulted in overcharges to the customers.

Florida Power Corporation

Fuel Supply Structure


Florida Power Corporation
Land ownership interest
Amvest Corporation
Electric Fuels Corporation
Lease
Murphy's Coal Company
Dulcimer Land Company
Little Black Mountain Coal Reserves
Sublease
Angus Minerals Company
Powell Mtn. Joint Venture
Homeland Coal Co.
Partnerships
Coal supply contract ⟶

TUCSON ELECTRIC POWER (TEP)

Tucson Electric Power (TEP) has found itself in difficulty recently as a result of management problems and utility self-dealing. "Tucson Electric Stock Plummets as Staff Urges Slashing Rate Bid," Electric Utility Week, March 27, 1989 at 1; "Harshly-worded Opinion Urges Tucson Electric Management Audit," Electric Utility Week, September 25, 1989 at 10. Although the Arizona Corporation Commission has not yet issued an order on this case, a hearing officer filed a recommended order that details some of the problems. Re: Tucson Electric Power Company, Docket Nos. U-1933-88-280, U-1933-88-090, Hearing Officer's Recommended Opinion and Order (September 18, 1989).

In the early 1980's TEP had excess generating capacity. In 1983, TEP received Commission approval to transfer two generating units to Alamito Company (Alamito), a newly-formed subsidiary. TEP stated that the purpose of the transfer was to separate TEP's wholesale and retail businesses. Hearing Officer's Opinion at 7.

Inter-affiliate Transactions--Generation

TEP entered into a Power Sale Agreement with Alamito in which TEP agreed to purchase the entire output generated by Alamito for twelve years. The agreement was drafted by TEP's Chief Counsel, Roland Hoch. It was signed on behalf of Alamito by TEP's Chief Financial Officer, Robert Johnson and on behalf of TEP by TEP's Senior Vice President, Einar Greve. "[T]he Agreement was clearly one-sided in favor of Alamito..." Id. at 7. The Agreement obligated TEP to purchase all of Alamito's power; it based the price of power on a fixed formula which set Alamito's equity ratio at 43%; and it allowed Alamito to unilaterally terminate its obligation to TEP at any time.

In 1984 TEP decided to spin off Alamito as an independent wholesale power company. TEP's Board of Directors approved the spin-off without any economic analysis of the spin-off having been performed. TEP's Chief Executive Officer, Theodore Welp, decided not to change the Power Supply Agreement before the spin-off since Alamito needed it to get independent financing. At the time of the spin-off, Alamito's equity ratio was approximately 18%, but TEP's formula price under the agreement was based on a 43% equity ratio. After the spin-off, Mr. Welp, Mr. Hoch and Mr. Johnson left TEP and became officers of Alamito. Mr. Greve became the President of TEP. Id. at 8.

In November 1985, the agreement was amended and the equity ratio used in the formula-based price was reduced to 30%. In June 1986, Alamito was sold to Catalyst Energy Corporation at a sales price $232 million above the price at the time of the spin-off. TEP was concerned about the Power Supply Agreement which obligated it to purchase power it would not need from a corporation that was no longer a subsidiary. After preparing a complaint seeking termination of the Agreement based on fraudulent misrepresentation, TEP opted to renegotiate the Agreement. The amended agreement reduced the amount of power TEP was required to purchase. The amended agreement also provided for the sale and leaseback by TEP of one of the generating units originally transferred to Alamito. The price exceeded the depreciated original cost by $220 million and the lease payments incorporate the inflated cost of the unit.

The staff of the Arizona Corporation Commission (ACC) recommended that the $232 million gain from the buyout should be realized by the ratepayers as a surrogate for the gain they would have realized if they had sold the units. However, the staff recommend allocating only 50% of the gain to the ratepayers because of the financial consequences to TEP. Hearing Officer's Opinion, at 9. The staff also found that TEP's purchase power costs were too high by approximately $45 million because of the Alamito spin-off. Id. at 10.

The hearing officer said that the ACC could not both recognize a gain from the sale of Alamito and also disallow some portion of the purchase power from Alamito. He termed these two options mutually exclusive. Id. at 10. He also found that the ACC had no jurisdiction over the generating units after it approved their transfer to Alamito; therefore, the ACC was precluded from recognizing any gain from the subsequent sale of Alamito. Additionally, approval of the transfer limited the Commission's jurisdiction over the prices Alamito charged TEP for wholesale power.

The hearing officer said that the ACC could determine whether any of the power TEP purchased from Alamito was excess capacity. "Although the stated objective of the spin-off was to separate TEP's retail and wholesale business, that objective was certainly not met since TEP's retail customers remained the primary responsible buyer of all of Alamito's power." Id. at 11. "In essence, TEP continued to have all the operating risk associated with [the two units] while Alamito enjoyed all the upside potential of selling the two plants at a gain. It was clearly an imprudent business decision to spin-off Alamito without amending the twelve-year Power Sale Agreement. We can not and will not permit ratepayers to pay for unneeded power resulting from this imprudent decision." Id. The hearing officer recommended a downward adjustment to the test year operating expenses of $32,592,295.

Other Interaffiliate Transactions

The ACC staff recommended a disallowance of $1.3 million in operating expenses saying that costs for items such as office space, computer and other services should be allocated between the regulated and non-regulated activities of the company. The hearing officer agreed with the staff recommendation which was unrebutted by TEP. Hearing Officer's Opinion at 34.

Avoiding Regulatory Oversight

Many of the problems at TEP seem to have stemmed from its efforts to avoid regulatory oversight. Spinning off its generation into an entity unregulated by the state commission turned out not to be in the best interests of the ratepayers, or even in the best interests of the company. The hearing officer described other problems in a section of the Opinion entitled "TEP Management". That section is quoted here in its entirety:

> One theme prevalent throughout the recent history of TEP has been its emphasis on shareholder/management compensation and disregard for its customers and this regulatory Commission. As state by JSA [Jobs for Southern Arizona, an intervenor]: "TEP has a very unhealthy attitude for a regulated company. It disregards its customers and concentrates its management efforts on behalf of its shareholders". The fact that TEP has not increased its rates for over seven years does indicate there has been some successful management. But there is no doubt, especially during the Mr. Ted Whelp era, that ratepayers were at best, secondary in concern. It is also clear from the numerous agreements reviewed in this matter that TEP stretched the regulatory limits as far as possible. As a result, the Company was reluctant to come before the Commission for a rate increase until financially it could no longer afford to wait.
>
> The Company has consistently made major decisions without any formal documentation. Again, as succinctly stated by JSA: "It is evident from the testimony of Mr. Greve that TEP's major decisions are made without the benefit of any third party recommendation, review or confirmation." We certainly do not believe that to be good management policy. While we are somewhat encouraged by the recent overhaul of management, we are still not convinced there will be the necessary attitude change consistent with that of a responsible regulated public service corporation. JSA has recommended that the Commission order that a "management audit of TEP's goals, objectives, organization, practices and procedures be instituted to assure that future performance consistent with that of a public service corporation is instituted". We concur and will order TEP to hire an outside, independent

reputable firm at a reasonable cost to conduct such an audit. Further, such an audit and the Company's corresponding actions should be filed for review with the Company's next rate case. Hearing Officer's Opinion and Recommended Order at 57-58.

Summary

TEP is a prime example of the difficulties a utility can suffer when the corporate management loses sight of the public interest and seeks only to promote corporate self-interest. TEP had waited longer than any other investor-owned utility to request a rate change. Its request for a $102 million rate hike was rejected by ACC staff who recommended only a $33 million increase. The hearing officer recommended an increase of $57 million.

TEP's rate difficulties and its other publicized problems (including the resignation of its CEO Greve after the disclosure of the insider sale of most of his stock) have damaged the value of its stock. On December 31, 1988 TEP stock traded at $41.75/share; on September 20, 1989, the stock closed at $24.25/share.

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SIERRA PACIFIC POWER COMPANY

The Nevada Public Service Commission examined self-dealing practices of Sierra Pacific Resources (Resources) and its affiliates at a rate hearing for Sierra Pacific Power Company (Sierra), a retail natural gas and water utility distribution service. The case is yet another illustration of the attempts of a holding company to abuse its monopoly power.

Resources is the parent company of four subsidiaries; Great Basin Energy Co., Lands of Sierra (LOS), Sierra Energy Co. (SECO), and Sierra. At the time of the hearing, Resources had 11 board members. Sierra had a nine-member board, all of whom were also on the board of Resources. All board members of LOS were also board members of Sierra. Re Sierra Pacific Power Company, 96 P.U.R.4th 1,7 (Nev. PSC 1988).

Cross-subsidies

The Commission began its discussion with an analysis of the impact of nonregulated subsidiaries on a regulated utility. Noting that one witness had testified that the loss patterns of the unregulated subsidiaries created higher costs for financing common equity directly and, possibly, indirectly, for debt financing, the Commission examined financial statements of LOS and SECO (unregulated subsidiaries) that clearly showed losses and it questioned the level of involvement of Sierra (the regulated subsidiary) in financially supporting the affiliates. Id. at 8.

The Commission pointed out that it had expected both shareholders and ratepayers to benefit from the reorganization. The holding company structure was approved in the face of two dissenting commissioners who had predicted that self-dealing would occur. The Commission said "It is apparent from the record in this case that the expectations of the concurring commissioners [in approving the holding company structure] have not been realized, and the fears expressed in the two dissenting opinions may be well founded." Id. at 8.

The Commission cited calculations showing that Resources had provided LOS and SECO with $57 million capital over the past five years. It added that the affiliation with Sierra was what gave Resources the ability to generate such capital. Of great concern to the Commission was the negative impact that the losses of the unregulated affiliates would have on the utility. The Commission decided to open a docket to examine the issue more thoroughly.

Self-dealing--sale at less than market value

Having decided to build a new headquarters, Sierra hired its affiliate LOS to act as a real estate agent and sell the property on which Sierra's present corporate headquarters were located. On April 13, 1987 at 2:00 p.m. Sierra's Board passed a resolution to sell its property to LOS. Austin Stedham, president and CEO of Sierra and a board member for both Sierra and Resources presented the LOS offer to buy the property for $2.75 million and recommended acceptance of the offer. At 3:30 p.m. the same day, the LOS board passed a resolution to purchase the property. Sierra's offer to sell the property for $2.75 million was presented to the LOS board by Joseph Gremban, chairman of the board, chairman and CEO of Resources, president of LOS and chairman of Sierra. No price appeared in either resolution. Three of the four LOS board members were also members of the Sierra board.

In November 1987, title was transferred to LOS for $2.75 million. Both Sierra and LOS were aware, prior to the November sale, that the owner of the property could sell it to a third party for $4.7 million. The Commission commented that in the face of eight valuations of the property ranging from $5.1 million to $2.75 million, Sierra chose the lowest.

The Commission was distressed over the self-dealing and said:

> An arms-length transaction is one negotiated by unrelated parties, each acting in his or her own self-interest and is the basis for a fair market value determination. ...[T]hese type of transactions were a concern the Commission had when authorizing the formation of the holding company format. At that time the Commission was assured by Sierra that transactions between the subsidiaries would be arms-length. This is not the case. ...
>
> Resources, as the parent company, and many of the subsidiaries have overlapping boards. ... The directors themselves seem to have difficulty remembering which hat they are wearing at any given time and whose interests are paramount to their considerations.
>
> ...Mr Gremban was uncertain when he received notice of offers to purchase the property on LOS letterhead whether he was receiving this information in his role with LOS or in his role with Sierra. ...
>
> Mr. Gremban testified that Sierra was not aware of the May 27, 1987 offer to purchase at $4.7 million since this was subsequent to the April 13 board meetings and LOS was then the owner of the property. ...
>
> The Purchase and Sales agreement was signed by Mr. Gremban as president of LOS. But he signed the Joinder and Consent Agreement, which bound not only LOS and Resources, but Sierra also, as president of Resources. ...
>
> It is unbelievable that the information these

> overlapping boards receive is only known to them when they are wearing a particular company's hat. This is especially true when the two companies involved have interests at odds with each other.
>
> Mr. Gremban, Mr. Ross and Mr. Fulstone and Mr. Plimpton of Sierra simply cannot conduct business at arms-length with Mr. Gremban, Mr. Ross and Mr. Fulstone and Mr. Plimpton of LOS. You cannot have an arms-length transaction with yourself. Therefore we find that Sierra is unable to conduct business at arms-length with LOS on any matters where it appears their interests are conflicting.

Summary

The Sierra Pacific case represents harm to utility ratepayers resulting from self-dealing. Officers of the utility holding company ignored their obligation to serve the utility rate payers, choosing instead to increase profits of the non-utility affiliate at the expense of the utility. The Nevada PSC may also find cross-subsidies when it completes its new docket.

OTHER AFFILIATE DEALINGS THAT PREJUDICE CONSUMERS

OHIO POWER COMPANY

Affiliate Transactions at Less Than Market Value

Ohio Power Co. and Indiana & Michigan Electric Co.(I&ME) are both subsidiaries of American Electric Power (AEP). I&ME has a division, the River Transportation division, that operates coal barges on the Ohio River for itself and other AEP companies including Ohio Power. Ohio Power owned some of the barges, as well as a barge headquarters which was not in its rate base.

In early 1986, the system applied for SEc approval of a system-wide pooling arrangement of its tug and barge costs, including a rate of return, which had not been charged previously. This rate of return would increase Ohio Power's fuel costs by about $100,000. The rate of return would increase automatically according to the rate set by the Indiana PSC for I&ME. Ohio Power's barges and the barge headquarters facility would be transferred at net cost to I&ME.

This transaction meant that not only would Ohio Power's customers start paying a return on these investments, but they would pay them to I&ME, not Ohio Power. American Electric Power Proposal to Operate River Barge division of Indiana & Michigan Electric Co., SEC File No. 70-7167

Contracts with Affiliates at Greater than Market Price

Ohio Power Company owns and buys coal from the Martinka mine. Although the FERC disallowed passthrough of Martinka coal costs in utility rates because the contract price was far above the prevailing market price for coal, the D.C. circuit overturned the FERC decision because the SEC had approved the return in the coal contract. The Ohio Public Utilities Commission has also allowed the contract price to control, and Ohio Power continues to purchase coal from its affiliate to the detriment of the consumers.

COLUMBIA GAS SYSTEM

Affiliate self-interest promoted

The Columbia Gas Development Corp. (Devco) is a subsidiary of Columbia Gas System, Inc., a registered holding company. Devco owns gas and oil leases and wells. It sells the gas output to its affiliate Columbia Gas Transmission Corp. (Transco), an interstate pipeline regulated by the FERC. When gas was first deregulated, Devco was also the buying agent for Transco for all of Transco's gas purchases in the Gulf and Southwestern states.

Devco negotiated gas contracts with producers for Transco. Once the contract terms were set, Devco would sign a contract for itself at the same terms if it had wells in the same field. For example, Devco negotiated for Transco with a producer for $9 per McF with 90% take-or-pay and then could obtain its own contract requiring Transco to pay under the same terms. Thus, Devco's incentive to find the best bargain for Transco was considerably compromised by its desire to maximize its own profits.

Contracts for more expensive options

When the Ohio Public Utility Commission reviewed Columbia Gas' gas cost recovery rates and its production and purchasing policies and their effect upon rates, it found that Columbia was not aggressively pursuing all available supply options. This occurred because Columbia relied heavily on its affiliated companies for its gas supply and did not avail itself of alternate less expensive supplies.

ARIZONA PUBLIC SERVICE

The Arizona Corporation Commission issued an order limiting dividend payments from Arizona Public Service to its parent holding company, Pinnacle West Capital Corporation. The ACC was afraid that Pinnacle West would use the dividend mechanism to transfer funds from APS to Merabank, a non-utility affiliate that was in severe financial difficulty. (In 1986 Merabank had earnings of $37.4 million; in 1988, Merabank had a deficit of $208.6 million.) Although no inter-affiliate bailout had actually taken place, the APS dividend rate had climbed to 88.7% of net earnings; the national average comparable dividend rate was 75% of net earnings. The Commission was unhappy with this transfer of profits away from the utility.

Pinnacle West has proposed filing for protective bankruptcy to keep from pouring money into its financially distressed affiliate. See Energy Daily, November 8, 1989. APS' ratings were cut by Moody's Investors Service as a result of the difficulties. Although bankruptcy of the parent corporation is not supposed to affect APS, the investment market often deals with perception rather than reality. The uncertainty of the parent's situation was considered likely to have adverse effects.

NIAGARA MOHAWK POWER CORPORATION

Preventing self-dealing purchases from subsidiaries

Niagara Mohawk purchases power from its two wholly owned subsidiaries, Canadian Niagara Power Co. and St Lawrence Power Co. The New York Public Service Commission examined these purchases saying, "Because of the interrelationship and potential for abuse, ...the interrelationship requires close scrutiny." Re Niagara Mohawk Power Corp., Opinion #87-3, 83 PUR4th 97, 110 (N.Y. Public Service Commission 1987). After careful investigation, the Commission said "we shall allow the contractual prices, subject however to a cap equal to the energy component of the SC6 avoided cost buyback rate. ...In this way, ratepayers will be protected against the possibility that the company may look to its subsidiaries instead of obtaining cheaper supplies elsewhere." Id.

CENTRAL ILLINOIS PUBLIC SERVICE CO.

Preventing Potential Cross-subsidies

The Illinois Commerce Commission adopted a compensatory payment scheme to reimburse rate-payers for unjustified cross-subsidization that occurs as a result of the holding company/affiliate structure. See Re Central Illinois Public Service Co., Docket # 86-0256, 101 PUR4th 193 (Ill. Commerce Commission 1989). The ICC required a payment to ratepayers of 5% of the dollar value of the transactions between CIPS and its affiliates. The ICC said that the affiliates would be considered as the holding company and any non-utility company of which the holding company owned a majority of the stock.

The Commission decided that this percentage was a reasonable amount to account for unquantifiable cross-subsidization that occurs simply as a result of the relationship between the holding company and its affiliates.

MONTANA-DAKOTA UTILITY COMPANY

Overpayment to an Affiliate

Montana-Dakota Utility Co. purchased coal from its affiliate Knife River Coal Mining Co., a wholly-owned subsidiary of MDU Resources Group Inc. The utility company is a division of MDU Resources Group Inc. The PSC determined that the utility had overpaid Knife River for the coal. Using a profits test to compare reasonableness of price, the PSC said that the utility had overpaid by $1,026,000 in 1985. Re Montana-Dakota Utility Company, Case # 10,799, 81 PUR4th 90 (N.D. P.S.C. 1987).

PUBLIC SERVICE COMPANY OF NEW MEXICO

Purchase from Affiliate at Higher Than Market Prices

The Public Service Commission investigated the price the utility paid its wholly-owned subsidiary, Sunbelt Mining Co., for coal. Re Public Service Company of New Mexico, Case #1693, 50 PUR4th 416 (New Mex. PSC 1982). The commission said "[B]oth the market price method and the rate of return method lead inescapably to the conclusion that Sunbelt's prices are too high." Id. at 441. Using the market return method of checking prices showed that the coal was purchased at a price equal to the highest priced coal in the area. The rate of return method yielded the conclusion that the profits were excessive--approximately 220%.

The utility had claimed that the purchases were proper because they were not purchases from its subsidiary. Sunbelt had sold the coal to the San Juan Coal Company. PNM said that since it dealt with SJCC, the transaction was not an affiliate transaction. The commission refused to accept this reasoning and said that PNM was ultimately dealing with its affiliate. The contract passed the Sunbelt price through SJCC to the utility. However, Sunbelt delivered the coal directly to PNM and billed PNM directly. Therefore, the PSC considered the transaction was an affiliate transaction.

Reorganization and Restructuring Proposal:

PNM proposed a holding company structure which would break PNM into the following subsidiary corporations:

Genco--this corporation would have PNM's electric generation and bulk transmission assets.

Disco--an electric distribution company holding PNM's electric distribution assets.

General Partner--would have operational control of Disco.

An expert witness testifying for the United States Executive Agencies had a series of unfavorable comments about the proposal.

"I believe the plan is not in the public interest for the following reasons:

a) Inadequate ability of the NMPSC to protect the interests of New Mexico retail customers of Disco, that is, assure their access to adequate electric utility services at just and reasonable rates because of (i) inadequate access of the surviving New Mexico jurisdictional utility, Disco, to competitive sources of capacity and energy, (ii) FERC preemption of NMPSC jurisdiction and (iii) inadequate NMPSC authority to prevent activities by Genco and its affiliates and sister affiliates detrimental to ratepayers.

b) Inequitable allocation of risks and benefits between parent company stockholders and Disco ratepayers in the proposed Power Supply Agreement (PSA) and Interconnection Agreement (IA) between Disco and Genco." p. 14

"PNM has structured the PSA to provide it with an assured revenue stream from Disco during the soft market period and increasing capacity to market outside the PSA once the market is expected to improve." p. 16

"Once Disco is free to purchase capacity from parties other than Disco, it is questionable that disco will have any realistic access to power sources other than Genco. Under PNM's proposal, Genco will retain virtually all bulk power transmission lines and have control over Disco access to power from competing utilities. The IA provides limited direct access for Disco only to Texas-New Mexico Power Company and Plains, both of whom have limited generating resources." p.17

"PNM proposes to retain [existing transmission] rights of way for Genco, although Genco will have no service obligation to NMPSC jurisdictional retail customers. My understanding is that new transmission rights of way are extremely difficult to obtain in New Mexico. PNM's existing rights of way were obtained by PNM because of its New Mexico utility franchise. Without access to these existing rights of way, it may be almost impossible for Disco to build its own transmission lines independent of Genco. ...This virtual veto power over Disco's access to transmission will ensure that Disco remains Genco's captive customer for generation." p. 18

"If a state regulatory commission allows generation to be put in a separate subsidiary or sold to a subsidiary, whether the subsidiary of the utility or a "sister affiliate," any sales by the subsidiary back to the utility serving retail customers becomes a sale for resale under the FERC's jurisdiction which limits the state commission's authority to control rates.

"My understanding is that, as a result of the so-called "Narragansett Doctrine," the Commission would have very limited ability to challenge the prudence of or disallow costs incurred under a wholesale power contract or interconnection agreement subject to the FERC jurisdiction." p. 20

"I do not believe a state's ability to regulate retail electric service in a manner that assures adequate service at just and reasonable rates should be impaired or eliminated through reorganization and restructuring schemes that result in FERC preemption over a significant portion of the costs included in retail rates. Both PNM's proposed reorganization and restructuring and, to a lesser extent, Staff's proposed structure have this effect.

"The only way the NMPSC will be able to attempt to protect New Mexico retail interests in the relationship between Disco and Genco or PNM and Mini-Genco will be to intervene in FERC proceedings." p. 25

The **Chairman**. Thank you, Mr. Hempling.

Mr. Smith, you indicate that you will be forced to do business with an IPP or you might be by the public utility commission. Would you explain how they would force you to do that?

Mr. **Smith**. Yes, I would be delighted to, Senator.

I think the risk of this becoming an involuntary requirement that utilities buy from the independent IPP but would not then be subject to the Holding Company Act and so forth is very real. You will have different situations arise throughout the country, no doubt.

And when one generalizes, you have to acknowledge that you are going to run the risks of extremes on either side, but generally speaking, when a state regulatory commission is asked to consider how electricity generation should best be provided in that area, under today's climate, there are tremendous pressures on those regulators to seek the short-term cost and the lowest price for consumers in the short-term which may not be the lowest price for consumers over the long-term.

And this is a balancing act that commissions have had to do for some time, and whether Senate bill 406 is enacted or not doesn't change that dynamic except what it does——

The **Chairman**. Well, now, the point I am making, though, is that this bill is voluntary. That is, according to the terms of this bill, you don't have to use it. You don't have to make a contract with an IPP. So, the question is how does Mr. Gray and his group force you to do it. He says he doesn't have any power under this bill.

Mr. **Smith**. I don't think it is Mr. Gray's position that this change in the law would be unlikely to encourage commissions to do anything other than require utilities to enter into agreements with those unregulated producers who, first of all, because of their own lower cost of capital because of their leverage, offered an apparent advantage in price for the short-term.

Now, we have seen what has happened in the few states around the country already with respect to decisions. I will cite the State of New Jersey recently which refused to approve a long-term purchase contract from a utility, opting for the encouragement of nonregulated generation, in this case QF generation, within the State of New Jersey.

You are going to have some very unusual things enacted by state commissions. I am not a state commissioner. There are no state commissioners in the room, so obviously no one can guarantee what a state commission will or won't do. But I have been involved in the electric business for 25 years and five years before that practicing law. I am very familiar with what state commissions are likely to do and the pressures that they have on them to opt for the short-term, nonregulated supply option whether or not over a period of time that——

The **Chairman**. Well, the mechanism of forcing is that they would disapprove the other alternatives——

Mr. **Smith**. Yes.

The **Chairman** [continuing]. Leaving you with only the IPP. That's what you're saying.

Mr. **Smith**. That's most likely the way it would happen.

The CHAIRMAN. All right.

Mr. BERRY. Mr. Chairman, can I respond to that?

The CHAIRMAN. Yes.

Mr. BERRY. It seems to me that the forcing process is kind of like when we go out for bids for coal. We are, in essence, forced to take the lowest bid or else prove why we took a higher bid. The only time a utility would have pressure from its regulator it seems to me to buy from an independent generator, rather than build, is when the independent generator offers a better opportunity, a lower cost and considering all the factors.

And instead of speculating what regulators might do, let me just tell you what regulators in Virginia have done. We went out for bids. We have been out for several rounds of bids, and in many cases the bids were significantly lower than what we felt we could build the capacity for ourselves. And consequently, we bought it.

But the last round of bids we had, which was for peaking capacity, which would have come under the provision of this act—it wasn't cogeneration--those bids were higher than we thought we thought we could build the capacity for. So, we rejected all the bids, went before the Virginia commission, carried the burden of proof to show that we could build it cheaper than we could buy from these independents whose bids we rejected. And the Virginia commission approved it.

I think regulators have the ability to make that judgment about which is the lowest cost source. And to some extent we are forced to buy from the lowest cost source, and that is not a pressure that I reject.

The CHAIRMAN. By the way, do you agree with Mr. Gray that he is powerless to do all these things he says he can't do, least cost planning, or he can determine an appropriate mix, or can't help choose between fuel technologies and reliability and those other things? Aren't they doing that now?

Mr. BERRY. No, I don't. And let me again not cite abstract or theoretical, but talk about practical issues.

The Virginia Commission after public hearings set a set of guidelines for bidding, and it gave utilities the option of either building or bidding. It did not require them to bid. We chose to bid, and then we had to bid under those guidelines. The commission evaluated the results of our selection. We have had numerous hearings on those issues.

We have had independent producers who have lost complaints to the commission. The commission has heard those complaints and rendered decisions one way or the other. We didn't like them all, but they sure in hell had the power to control the process.

The CHAIRMAN. Well, let me ask Mr. Smith. Do you agree on the narrow point of the power of PUCs to do these things?

And I will get back to you in just a second, Mr. Gray. It seems to me that Mr. Gray's concern with the Mississippi Power case is greatly overblown. It is a very narrow decision dealing with only interstate holding companies. And I think PUCs across the country are doing all the things he says that they can't do now. Do you agree with that?

Mr. SMITH. Well, Senator Johnston, of course, it varies from state to state, and I am not an expert on the Grand Gulf case and the way in which Pike County might impact that. But state commissions by and large do have very substantial powers with respect to their ability to disallow certain costs that a utility has incurred.

But I think there is, obviously, the Grand Gulf FERC allocation decision that still creates controversy. And I would not speak for the NARUC and the different states to say from place to place whether they do or do not have the right to overrule the Grand Gulf FERC decision. My impression would be that they probably don't.

The CHAIRMAN. Without getting into the nice, fine points of that decision, it seems to me that at the heart of this debate is whether the tremendous additional powers which this bill would give to PUCs ought to be lodged in PUCs. In effect, I think it is taking power, according to you, Mr. Smith, from utilities and giving it to PUCs. And the PUCs say we don't have the power and apparently we don't want the power. Is that fair, Mr. Hempling?

Mr. HEMPLING. In a certain context it is, Your Honor. I knew that would happen today. Mr. Chairman. [Laughter.]

I assume you view that as a promotion, not a demotion. [Laughter.]

Senator CONRAD. That's a real breakthrough up here this year, Mr. Chairman. [Laughter.]

Mr. SMITH. Your Excellency, may I expand on that? [Laughter.]

Mr. HEMPLING. I wasn't going to go that far.

Mr. SMITH. With respect to what the commissions may disallow under this legislation which you have touched on, that is another matter of concern that the utilities which are in our group have a great deal of concern about.

The bill in the last section speaks only to preserving state jurisdiction ostensibly for the purpose of states disallowing the costs that utilities would incur if they purchased this IPP power.

Now, I would hope that is not the intent of the bill, that the intent of the bill would just be to preserve the status quo because one of the difficulties that utilities are already facing under PURPA is that many of them have had to buy power that was not needed at much higher than the utilities running costs, and they haven't been able to recover all of those costs through the state mechanism. And so, we are concerned about that particular portion of the bill.

The CHAIRMAN. We don't mean to bless that situation at all by this bill. Not at all.

Mr. KEARNEY. Mr. Chairman?

The CHAIRMAN. Mr. Kearney.

Mr. KEARNEY. I would like to just add a little bit of broader flavor of experience because we are dealing in many jurisdictions across the east coast and, for that matter, across the country where capacity is required. And in all the jurisdictions where we are active, the problems that Mr. Smith alludes to are not real.

The CHAIRMAN. You mean the problems under PURPA of——

Mr. KEARNEY. Under PURPA and the forcing to buy and, for that matter, the short-term perspective on the part of regulators. No regulator any longer is looking at the next two or three years. All of the contracts that they are dealing with are looking at the 20 year horizon and looking at least cost for that 20 year period of time. There is nobody looking at two or three years, and they are comparing the alternatives of utility purchase and utility build on that kind of perspective.

I think you have to assume that the players in the game and the regulators learn from past experience. I don't think Mr. Smith is reflecting that. The system, the procedures and the arrangements that now are being talked about are very, very different from the kind of scare problems that did exist previously.

The CHAIRMAN. Well, I will want to ask on my second round of questioning here about PURPA and its success not because it determines whether this bill is good or not, but because it is a related and interesting question.

Let me ask one more question on my first round here, and that has to do with reliability. It seems to me that reliability could be insured by contract. What does reliability consist of? It consists of economic ability and technical knowledge and various other things which you ought to be able to ensure by contract. Isn't that so, Mr. Smith?

Mr. SMITH. Certainly the contracts would seek to deal with that. The contracts, however, could not possibly give the utility operator the same control as the ownership and the operation of the facility. But it's a question of risk.

The CHAIRMAN. Suppose you said that if you voluntarily shut down this IPP, you have to pay $1 million a day and you have to put that in an account over here insured by a bonding company. Can't some mechanism like that ensure the next best thing to your control?

Mr. SMITH. Well, a provision such as you described I don't think realistically would be required in one of these contracts. I wasn't here last week when the debate ensued over whether PURPA cogenerators in Texas acted properly or improperly when Hurricane Gilbert came through. I think there was some discussion as to whether or not they were going to shut down. They didn't shut down because the hurricane didn't come through.

The question that I think is basic is whether or not a large amount of non-controlled generation, non-controlled by ownership on the utility system, does raise the risk of reliability if you just have a small amount of it on your system—that is, contracted-for IPP generation—then obviously you are probably going to be able to work around it, and it is not likely to have a significant adverse impact. If you have a large amount of it, and you don't control it, then you do have a much greater risk to the reliability of your system than if you owned and operated it.

And as I see the utilities during the 1990s, no matter how much non-utility generation there is—and there are different estimates, but let's say there is a significant amount—and one can put their own figures on what is significant—we in this country are still going to have to build a large amount of baseload, either fossil fired or nuclear electric utility generation for the future.

And my concern is that what would happen under this legislation is a series of events that would make it much more difficult for our utilities to build new fossil fired and new nuclear generation in the 1990s to serve beyond the next century because in the state utility arena, we would be challenged by the competitive—

and I would say it is not fair competition. It is certainly not fair competition. But we would be challenged by that competitive entrepreneurial IPP who would say don't allow the XYZ utility company—don't give them permission to build this large coal-fired plant or this large nuclear plant because what you should do is allow us to build a smaller gas fired plant at whatever these market avoided rates are. And that is a real risk.

I don't have any hesitation in saying that that in my opinion will certainly happen.

The CHAIRMAN. Let me ask Mr. Berry to reply to this business of reliability. Are you reliable and if so, how are you made to be reliable?

Mr. BERRY. Well, I think we go through a series of steps to assure the reliability of the contracts, beginning with the bid evaluation where we put a substantial weight on the reliability of the project in terms of the nature of the owner, the nature of the project, where it is located, how it will be built in the selection process.

Then we put in incentives for performance and penalties for performance. We avoid putting risks on the independent generator that he can't control, but put risks on him that he can control.

We do look at portfolio projects that are modest in size. We don't put all of our eggs in one basket.

And finally, we have a contractual right to step in and acquire the project fair market value if they fail to produce. Having the right to sue under the contract doesn't give you the kilowatts. You have to have the right to step in and take it over if they fail.

The CHAIRMAN. How much coal do you have?

Mr. BERRY. Well, the 3,000 megawatts that we purchased through competitive bid, 70 percent of the energy produced under those contracts will be coal. It is that way because that is the way we wanted it. In fact, the bids were much more attractive for baseload coal fired capacity than they were for intermediate and even less so for peaking, and as I indicated earlier, we rejected the bids for peaking capacity.

The CHAIRMAN. Can you imagine that IPPs would be building baseload plants, nuclear as well as coal?

Mr. BERRY. Well, there is a difference of opinion about when the nuclear option is coming back and how. I don't think there is a lot of argument of whether, but I think it's a question of when and how. In my judgment, we are most likely to see the next round of nuclear construction be in the form of an independent power generator because that first nuclear unit or the first wave of nuclear units is going to involve risk, high business risk, not safety risk. And you need to have a balance of risk and award, and high business risk doesn't fit with the utility regulatory process. It does fit with the competitive marketplace. So, I think you are likely to see new nuclear come in the form of independent power production if we make it possible for it to happen through this bill.

The CHAIRMAN. Let me let my colleagues get in on this. I know some of you want to reply to some of this, but I don't want to take this whole thing. I think Senator Nickles was next.

Senator NICKLES. Mr. Chairman, thank you very much.

I, Mr. Chairman, might ask you a question before I ask the panelists. I heard the majority leader state today that when we reconvene next session, that we would start on the Clean Air Bill I think January 23. It is on a Monday. I would hope that this committee would have some hearings on the bill as reported out. And I am assuming it is going to be reported out today or before we adjourn. Would that be possible for us to do that?

The CHAIRMAN. It is hard to have hearings when we are out of session.

Senator NICKLES. Well, possibly that first week when we're back?

The CHAIRMAN. Yes. I think that would be useful.

Senator NICKLES. I think it would be very helpful and I would encourage you to do that and hope that we can.

Senator CONRAD. Would the Senator just yield on that point?

Senator NICKLES. I would be happy to.

Senator CONRAD. I would just like to add my voice to that. I really think it is terribly important that we have a chance to review what is coming out before it goes on the floor or at least concurrently so that we have a chance to provide our input because this is going to have implications that go beyond the Environment and Public Works Committee.

Senator NICKLES. Certainly. And I appreciate, Senator Conrad, your comments and appreciate the Chairman's willingness.

The CHAIRMAN. I think we have some time that first week, so I think your suggestion is a good one. We will try to do it that first week.

Senator NICKLES. Well, I appreciate that, Mr. Chairman.

Also, I appreciate the consensus that the panel has on this legislation. [Laughter.]

Senator NICKLES. No. It is informative, and I appreciate the Chairman's comment.

I have been contacted on both sides of this legislation, but it is kind of interesting. Mr. Smith, how do you respond to the statement or allegation that you are opposed to legislation because you are afraid of competition?

Mr. SMITH. Simply by saying that that statement, if it has been made, is not true. There is already a significant amount of competition in the bulk power supply market.

What one has to keep in mind when you talk about competition in our industry is, first of all, the consumer is the person whose interests should come first and I think must come first. That consumer over time has proven to be better served under a regulated monopoly system than true, wide-open competition because through the regulated system you have had an assurance of reliable service and, more importantly, you have had the prevention of uneconomic and wasteful duplication of facilities.

And one of the issues that anyone has to deal with as you look at legislation like this is to what extent you will have uneconomic duplication of facilities through stranded investment. The utilities that are now serving retail customers are doing so by having raised large amounts of capital, built the plants that are intended to operate for 20 or 30 or even 40 years.

To the extent that because of legislation, because of regulatory decisions or a court decision it becomes possible for new entrants who are not regulated to enter the field and begin serving either resale customers—that would be municipal systems or REA loads—or large industrial customers, you are going to divert revenues from the regulated system to the nonregulated system and leave those still served by the regulated system paying much higher costs than they would otherwise. And it is also going to have serious adverse effect upon the investors in the regulated system.

So, I say that to the extent that there is competition, it should be competition that considers whether or not there is likely to be stranded investment, whether or not there is likely to be wholesale bypass or retail bypass and loss of revenues to the regulated system and higher cost to those that can't leave the regulated system.

It is an oversimplification, Senator Nickles, to say it is just a question of should we or should we not have competition. That is really not the question here. It is what type of competition should we have and to what extent should the customers of the regulated system be protected.

Senator NICKLES. Let me ask you a follow-up question about it. I think a couple of other people might want to respond.

Mr. Kearney, just to kind of ask you a direct question, why or how can you come up, or Mr. Berry, either one, with the additional incremental units or powers cheaper than the "regulated" utilities since your cost of capital in all likelihood would be higher? How are you able to offer consumers a competitive price advantage over an existing regulated utility?

Mr. KEARNEY. I can answer that in two ways. One is that the reality is that the competitive power plants out there now today are doing just that. And the way that they are doing it is by being slightly more innovative, being more aggressive with regard to managing their activities than the existing regulated part of the business.

Now, we don't exclude in our concept the possibility that the regulated entities will become very competitive, and they will have to because we are there. They will have to learn how to really manage their projects and be innovative in the competitive process. When we look at a competitive bidding situation, we know that we have got to put on the table the most cost-effective plant or we will not get that opportunity to sell. That creates a tremendous force for innovation, imagination. And I think it can be structured in a way that it will likewise be both cost effective to the customers as well as reliable.

Mr. BERRY. If I could pick up on that. I think the free marketplace is an amazing process. It is clearly superior to government control, as the whole world is beginning to realize. The free market imposes some harsh disciplines. In a way it is the toughest of all regulators.

If you look at the variation that has existed in the cost to building nuclear plants from one utility to the other, you have to come to the conclusion that maybe some of them are building them better than others. In a free competitive marketplace, you would buy power, and the guy who would survive would be the one who is successful, who can do it well, and the other one would die.

The Chairman. If the Senator would yield at that point. What is the cost differential and the cost per megawatt of utilities using the same nuclear technology? How much differential is there?

Mr. Berry. It is difficult to compare that because of the different timing, but taking the gross numbers, we have four nukes that cost us about $500 per kilowatt, and there are a number being built today at $5,000 a kilowatt.

The Chairman. Well, that is a difference in timing. Could you give us sort of a——

Mr. Berry. I think within the same time frame you will see a two to one instead of a 10 to 1 ratio.

The Chairman. Is that due to competition or regulation?

Mr. Berry. Well, there isn't any competition there. I don't know what it is due to.

The Chairman. I mean, due to management, should I say?

Mr. Berry. I don't know what it is due to, but all I know is that in a competitive marketplace, if you were producing at twice what the marketplace was able to do, you wouldn't get the business.

Senator Nickles. Let me ask you a question, Mr. Berry. You are supportive of the legislation as it is. Would you support it if it was amended as suggested by Mr. Gray?

Mr. Berry. Well, I am not a lawyer and the vagaries of Pike County and the Mississippi Power & Light case sort of escape me. I really don't see where they apply to this issue.

He wants some clarification that this bill doesn't take away any state authority. In my judgment it is not intended to do so, and if it would make him feel better to have that in there, I wouldn't object to it. To say in there that contrary to any law, state authority it seems to me is sort of extravagant legislation. To say that this act does not take away any state authority would be perfectly acceptable to me.

Senator Nickles. Mr. Gray?

Mr. Gray. I would be happy to respond to that.

It seems to me the central is not——

Senator Nickles. Do you oppose the legislation unless you could get those amendments in it?

Mr. Gray. Yes, and the reason is that we know that state jurisdiction as the result of wholesale sales approved by FERC is preempted or is likely or could be preempted in at least half a dozen situations through half a dozen means. This bill would open up the market to more wholesale sales bringing greater pressure.

And at this point we've seen—I guess you would say that the utilities have acquiesced in the state regulation of their wholesale purchases. Frankly, that is not enough for us. We need legal certainty rather than utility acquiescence in the state commission exercising jurisdiction over purchased power acquisition.

We know that registered systems under Mississippi Power & Light—there's preemption there. We know that multistate systems—Nantehala—there's preemption there. There may be preemption in——

Senator Nickles. You just want to make sure that they would be under state regulation.

Mr. Gray. Correct. Yes, sir. And this bill would exacerbate an ongoing problem clearly.

Senator NICKLES. Mr. Kearney, if they were under state regulation, would you still be supportive of the bill?

Mr. KEARNEY. I believe right now they are under state regulation. I believe that the states are really exercising their regulatory authority in the areas where we are dealing. And they are effectively planning. They are effectively moving. Even utilities that are members of multistate holding companies are being moved now to act by their state regulatory agencies and act effectively in their buying, thus avoiding the problem that Mr. Gray identifies.

However, from our standpoint with regard to the bill, I think if you found that it was necessary to clarify that as a legal matter, then that would be something that would be up to you. I don't speak as a lawyer. I am just talking from the standpoint of what is practically happening, and I don't see that as a major issue.

Senator NICKLES. Mr. Hempling, you basically testified in opposition to the legislation, or at least I was catching that to be the primary thrust. You don't think the legislation would increase the competition and therefore bring prices down?

Mr. HEMPLING. Senator, the answer is no. What the legislation could do is increase the number of competitors on a temporary basis as the barriers created by the Holding Company Act are eliminated.

The long-term question is whether that large number of new entrants remains. The concern consumers have is if the additional number of entrants occurs without market structure protections, which include access to the highways, then that large number of competitors over time can diminish leaving us with the same small number of competitors as today.

We fully support the thrust of adding competitors to the market, and quite bluntly in my testimony we make clear that there are barriers in the act that consumers could benefit from having adjusted to add new entrants. But simply to add the entrants without making the structure competitive could leave us with less competition than we have today.

Senator NICKLES. I looked a little at your statement. It was about 80 pages. I may not read all that tonight. [Laughter.]

But I would still think from your perspective that you would think it would be advantageous to open it to as many competitors as possible. And then, yes, if you had some that came in and then possibly didn't survive, you might end up probably no worse where you are today, or at least I would think that that would be the case.

Mr. HEMPLING. That's something I just cannot predict, Senator. The history of this industry is a history of monopolists benefiting, as it is their fiduciary obligation to do, from the monopoly facilities which they own. And so I maintain the position that really adding entrants would not necessarily increase consumer welfare.

I do support the view that we should add the number of fair competitors, and I am very willing to work on that subject with you.

Senator NICKLES. Mr. Smith, one final comment. I think I heard in part of your response—and I'm interested in this—is part of the concern that a lot of the utilities have is that you would have some of these incremental units coming on and taking away some of the best customers, some of the more profitable customers, therefore leaving the base in a less profitable situation.

Mr. SMITH. Yes, that is one of the concerns.

And, Senator Nickles, may I add a comment to a question you asked earlier?

Senator NICKLES. If you have a major utility and you have a few industrial customers, say, that comprise 30 percent of your sales, good customers, high volume, maybe they are purchasing power when you want to sell it or whatever, to where it financially works out well for you. You wouldn't want to see another independent group come in and take that customer away and therefore have to amortize cost, et cetera, over either a smaller base or a less profitable base.

Mr. SMITH. Exactly. What would happen is the cost of service to the remaining customers would go up because you would have the same cost investment spread over fewer customers, fewer kilowatts and fewer kilowatt hours.

And you would have the risk of large industrial customers shifting back and forth. The smaller residential, commercial customers would not be able to do that. But if you began to lose large segments of your load—and for some utilities a very few, less than 10, large industrial customers might represent 40 or 50 percent of their total load. It would be a very, very high percentage. So, that is a very real concern.

If I might add a comment——

Senator NICKLES. Let me just follow up to the point I was trying to make. Shouldn't those large industrial customers that may make up 20 or 30 or 40 percent of their load have the opportunity to keep you competitive? And, therefore, if they found out that you were putting a significant percentage of cost, maybe an over-percentage of cost in their viewpoint, on them, shouldn't they have the opportunity to look elsewhere?

The CHAIRMAN. If the Senator will yield. I think it is important at this point to point out that this bill relates to wholesale sales only. It doesn't relate to retail so that this creaming off the retail customers could not occur under this bill. And for that reason in my judgment the wheeling question is not very important in this bill. I mean, I know it is a big, hot issue, but I don't believe it is that important in this bill, although I will want to come back and examine that.

Excuse the interruption.

Senator NICKLES. I hadn't really thought of it until Mr. Smith had mentioned it earlier. And I was catching that as one of the reasons why—as a matter of fact, I think you said it's one of the reasons why you didn't want to see it happen. You were afraid that some of the better customers might be I am going to say picked off or——

Mr. SMITH. That's a good word.

Senator NICKLES [continuing]. You might lose them to competition.

Mr. SMITH. Yes, that might happen conceivably through sales to a newly created wholesale broker or sales to a municipal system as we view the possible impact of the act, although the act, as Senator Johnston correctly stated, does not encompass by its terminology sales other than sales at wholesale. But we are afraid that the sales—there could be created a bridge that the wholesale seller would be able to use to take the retail customer.

Under the regulated system, all of the customers have the opportunity and do vigorously exercise that opportunity to appear in the ratemaking process before their respective utility commissions. And the utility commissions then have the responsibility to determine what is the appropriate investment to be used for setting rates for a large body of customers. And those facilities are not entitled to earn at market rates. They have, first of all, no guarantee that they can earn a certain rate of return, but there is an allowable rate of return that is set by the commission. And rates are set with the expectation that, properly managed, the company should be able to earn that rate of return.

Now, if you begin from time to time to reach in and take groups of customers out of that universe——

Senator NICKLES. I understand.

Mr. SMITH [continuing]. Then you sharply alter the costs that different customers who don't have the freedom to move around would bear. And I think Mr. Gray and all of the state commissions would agree that that would be a tremendously adverse thing to impact the customers and impact the utility systems with.

If I may add a comment about an earlier question that you asked, Senator, with respect to the perhaps differences in costs of an IPP generator and a utility built generator. The major difference in cost we submit would have to come because of the IPP's lower cost of capital. The IPP would use——

Senator NICKLES. I would expect that the utility could get the lower cost of capital.

Mr. SMITH. No. The IPP would have the lower cost of capital because it would be financed almost entirely by debt. The interest on that debt would be tax deductible. So, the marginal cost rate of the IPP might be 30 percent whereas the regulated utility industries might be 44 or 45 percent.

In our prefiled testimony for the Electric Reliability Coalition—and I believe this appears about pages 26, 27 and 28—there are some illustrations that show how the lower marginal cost tax rate of the IPPs coupled with their use of much more debt than we can use would lower their cost of capital.

Now, some of the rating agency commentators who have looked at this have said that the utility, which would then have the obligation under these IPP contracts, will over time have higher costs, and just like long-term leases, those are going to be imputed as an obligation which is going to tend to raise the utility's cost of capital and raise its risk. And over time you would have questions about utility bond ratings, whether or not they should perhaps be adversely impacted utility of the large quantity IPP——

Senator NICKLES. But you have IPPs that don't have the I am going to say the basis or backing that the utilities have. The utilities for the most part are——

Mr. SMITH. But the IPPs, Senator, have the contract with the utility, and it is on that basis that they are able to finance. They have the contract. You might call it a take or pay or take and pay, or some of them are front end loaded with high capacity charges paid early. And it is on that basis and the assurance that the utility will be obligated to pay the IPP that they are able to finance.

Senator NICKLES. Thank you very much.

Mr. KEARNEY. Senator Nickles, can I comment on that?

Senator NICKLES. Yes.

Mr. KEARNEY. This is a very complex matter, and I don't think it is useful to get into a comparison of costs that are incurred by the utilities in their performing their function of building plans versus an IPP's cost.

However, on the issue of the leverage, I think it is really clear that we are taking risks from the utilities and putting them on this IPP. What we have done, which is available to the utilities themselves, is manage that risk so that we can decrease the costs of our total financing by increasing the cost of debt. And the way that we do that is not leaving the risks or increasing the risks on the utility, it is farming out some of those risks from the project to the fuel supplier to the constructor. So, those risks are really on our side of the table. We have managed to handle those risks in a more imaginative and lower cost fashion. And that is the reason why we can have higher leverage and therefore lower true costs to the customers.

Mr. BERRY. Senator, could I just follow up? Getting away from the theoretical world to the real world again, Virginia Power has under contract about 3,000 megawatts of capacity. Virginia Power's equity ratio is about 40 percent. Our A plus debt rating was just last month affirmed by all of the major rating agencies. So, it hasn't affected our credit quality even though that is under contract right now.

On the other hand, if we had built that 3,000 megawatts of capacity ourselves or were trying to build it, we would be in the process of raising $3 billion or $4 billion, and I can assure you that our credit rating would slip under those conditions.

Senator NICKLES. You would have to raise how much if you did?

Mr. BERRY. Three or four billion dollars to pay for 3,000 megawatts that is under contract, and that investment is being raised by the independent generator, not by us.

Senator NICKLES. Good point.

Thank you, Mr. Chairman.

The CHAIRMAN. Thank you.

Senator Conrad?

Senator CONRAD. Thank you, Mr. Chairman. I would like to ask Mr. Smith if you were to look ahead 20 years and this bill were passed as is, what would be the differences between the development of the industry from no bill?

Mr. SMITH. Senator Conrad, I have often thought about that. And I have to claim or admit fallibility and admit, obviously, I don't know. I do have some ideas and some concerns.

If you look back as a starting point and try to imagine what the industry would have looked like of this bill had been a part of PURPA, then I think today we would have a system where many of the large baseload generating plants, fossil and nuclear, that the utilities were able to complete—were unable would not have been completed. So, you would have today a smaller utility regulated base of generation to serve the public. And so, I think over the next 20 years, the same thing is likely to happen. I think you would have a much smaller base of regulated utility owned and operated generation than you would have non-utility owned and operated generation.

The costs of capital, depending upon various tax rates and whether or not they are investment tax credits, can usually be recovered over a short period of time from a cogeneration facility or an IPP facility. Certainly during the next 20 years, the full cost of capital of the IPP generation would have been recovered. So, you would have facilities being operated by owners who no longer had their capital at risk. That would give them a great deal of freedom of action.

As their 20 year or 15 year contracts expired, we would be in a situation where amount of electricity was not subject to regulation. That is, it was not obligated to serve the system. It had had its costs fully recovered, and there would be in effect a de facto unregulated monopoly system because you would have essential resources essential to the public service not owned by entities that were obligated to serve the public.

And I don't think you would see the government take those over by eminent domain. That is one thing that in theory in could happen. I don't think would happen.

But it would be very interesting to see whether the rates the consumers then were required to pay were higher or lower than rates the consumers would pay if that same amount of generation and the low embedded costs were owned and operated by the utility system. My instincts are that it is quite likely that consumers then would be required to pay much higher rates for the same amount of power than if they were able to buy from the same amount of generation owned and operated under the regulated system.

But again, these are concerns that I have and, obviously, I don't know. But I think these are very legitimate concerns.

Senator CONRAD. Let me ask Mr. Berry that same question. Twenty years out, what are the differences with and without this bill from your perspective?

Mr. BERRY. Well, like Mr. Smith, I am not clairvoyant. But it seems to me the important thing is not where we are out 20 years, but the fact that we are talking about an incremental move towards competition and away from regulation, a gradual incremental move where we will have ample opportunities over the next 20 years to adjust this.

And if there is anything we should learn from our experience with telephones and airlines, is that we don't want an abrupt deregulation of this industry that has been regulated for so long. What we want to do is gradually move in the direction of competition, and then adjust.

Now, if competition has all the wonderful things that I believe it has, then 20 years from now, as Mr. Smith points out, you are going to see more of the generation in the competitive marketplace and less of it in the utility regulated sector. And if you want to go out 40 or 50 years, you might see zero in the regulated sector. That is if competition works. If it doesn't work, then over that 20 years we will make some adjustments.

Senator **Conrad**. Let me ask you, Mr. Berry, a follow-up that attaches to levels of risk. You earlier talked about the nuclear plant and a new nuclear plant coming on would be a high business risk. You emphasized business risk, and I think that was appropriate. I have a question that attaches to the question of business risk generically as it relates to IPPs.

Isn't there an incentive to have a higher level of indebtedness, and doesn't that mean most assuredly a higher level of risk attached to these projects? And shouldn't that be something that concerns us as we point in this direction?

Mr. **Berry**. Well, I think, as is true in most situations, if you look at the total envelope, there is no change in risk. We just are assigning those risks to different entities. There is a shifting of risks that occurs if you look at utility construction as opposed to IPPs.

For example, the risks associated with construction costs, the risks associated with completing the project on time, and the risks associated with operating the unit in accordance with the contract, all those risks that are now borne by utilities and their customers would now be shifted to the independent producer.

Fuel price risk, the general cost of fuel, not a specific contract, but is oil is going to triple or something like that, is now borne by utilities and their customers. And we think that under a good contract they should continue to be borne by utilities and their customers.

And finally, there is the need for power. Do you really need this project? That risk is now borne by utilities and their customers and it would continue to be borne by utilities and their customers.

So, we have a number of risks that are shifted away from utilities and their customers, construction, completion on time and operation. We have a number that remain the same. And on the other side you would have to say the utilities are taking on the risk as to whether these people actually perform under contracts. So, we have a shifting of risks.

And I described earlier. I think there are steps that we can take to control the risks of contract performance. And as Mr. Kearney mentioned, there are steps that these independent generators can take to manage those risks that they are taking on like construction.

Senator **Conrad**. Perhaps you addressed this part of the question, but I didn't catch it if you did. One of the concerns that I have is that you have a higher incentive to take on debt to finance IPPs than regulated utilities. Is that the case? Is that a fair assumption or not?

Mr. **Berry**. It is definitely true that IPPs have higher leverage, higher percentage of debt than utilities do.

Senator **Conrad**. And, in fact, the tax system encourages that.

Mr. **Berry**. I would say, yes, it encourages it. The system encourages anybody to take on as much debt as they can because of the treatment of taxation encourages you to take on as much debt as you can without jeopardizing your credit worthiness. And utilities do that. We take on as much debt as we can without jeopardizing our credit rating because that keeps rates down.

Senator **Conrad**. But IPPs generally are going to have a higher level of debt than existing utilities.

Mr. Berry. That's correct.

Senator Conrad. And doesn't that tell us that we are going to have a higher risk factor attached to these facilities?

Mr. Berry. No, sir, I don't believe so. They have to counterbalance that risk. The utility retains some risk, as I have indicated before, market risks, fuel price risks, and that we have a contract with the independent generator that shelters him from that risk and therefore he can take on that debt without adding to his business risk.

Senator Conrad. I would like to come to Mr. Kearney if I am pronouncing it correctly. Let me just again make the observation. We watched what happened to the S&L industry. There was a move toward deregulation there allowing them to take on higher risk investments, moving out of their traditional field, and we reaped a whirlwind. Now, there are lots of factors attached to that, regulation, a whole series of things we all know about.

It sends to me at least a cautionary signal on moving in this direction with respect to this industry. And I know they are not precisely related, but there are elements that are the same.

Why shouldn't we be concerned?

Mr. Berry. Well, the savings and loans took on those risks and that high leverage without a contract on the other side. I don't think there is an analogy there. The contract that the independent producer has with the utility is an assurance of payment regardless of market demand and regardless of fuel prices because those two items in my judgment in a good contract continue to be utility and utility customer risks.

The Chairman. And there is no FSLIC in this bill either. [Laughter.]

Mr. Berry. Yes, there are no government guarantees of that debt.

The other risks that are with that independent producer, if he is as smart as most of them are, he lays those risks off. And I think Mr. Kearney can address that better than I.

Senator Conrad. Mr. Kearney and then Mr. Hempling.

Mr. Kearney. Thank you, Senator.

With regard to the debt question, I don't know of any bank who is taking any risks in either case whether the bank is loaning to the utility or the bank is loaning to the independent power producer. When he looks at these projects or he looks at anything, he is a no-risk participant. So, when he looks at the utilities example where there may be 50 percent debt, he is reflecting the fact that there is higher risk associated with the way that that business—the way those plants are going to be built.

When he looks at a private power producer, as we have said, I have taken on a significant amount of risk from the utility, but I have also, by bringing in other participants, been able to move that risk elsewhere so that the reality is there isn't any higher risk in the way that you raise it on the power producer simply because his debt ratio is higher. The banks aren't going to allow that. If there was any higher risk, we would not be able to finance to the 80, 90 percent level which is generally where these are financed at.

The reality from the risk standpoint is that the risks have been moved to other players, the contract with the constructor, for example, which has been the classic large, large risk on the utilities, cost overruns, plant schedules and performance. Now, that is all undertaken by the contractors, and that is significantly why we can take these higher debt ratios, and it does not reflect any higher risks to the project itself.

Senator CONRAD. I just want to tell you my gut reaction to that is I am very skeptical when I hear people tell me there is no risk.

Mr. KEARNEY. No. I correct myself if I left that impression. You have to be very careful about that risk. That is absolutely correct. And you should be cautious about it. I think we need to look very carefully at the individual situations. My point of view is as I indicated, but it is not something to be dismissed.

Mr. HEMPLING. Senator, I agree with your concern about risk. The risk, of course, is the risk of the economic nature of a project or the financial structure or the corporate structure. It does not necessarily go to the identity whether it's a utility or an IPP.

My point in my testimony is that the Holding Company Act presents a unique advance check on precisely the risks that you are concerned about. In fact, it was precisely financial risks of leveraging, among other concerns, that led to the passage of the act. Now, certainly today there are different kinds of risks than the ones 50 years ago, but the basic concern about business risk, about entrepreneurial advance into new territories remains in this industry.

There are those who argue that the Holding Company Act is unnecessary because other statutes, such as the Federal Power Act, can protect us from this risk. The whole premise that Congress operated under when it passed simultaneously the Holding Company Act and the Federal Power Act was that there were certain kinds of risks that cannot be redressed after they have come to bear. And so, it is precisely the prestructural review that the act gives us that I believe can address your concern about risks without making the basic judgment as to who ultimately should play in the markets.

Thank you.

Senator CONRAD. So, if that kind of change were adopted in this legislation, that would change your view of the legislation.

Mr. HEMPLING. If the legislation retained the central aspects of preacquisition review, then it would fundamentally change a good deal of the consumer position on the statute. Yes, sir. We have, as I discussed with Senator Nickles, no objection to removing unnecessary barriers to fair competitors. I think we need to work in that direction.

Senator CONRAD. Do I have additional time, Mr. Chairman?

The CHAIRMAN. Yes, but if I may jump in if you would yield on this.

Senator CONRAD. Yes, would you please.

The CHAIRMAN. You say you would not object if there was preacquisition review by the PUCs—or by the SEC.

Mr. HEMPLING. Senator, the question as to what entity, what governmental entity, ought to conduct the preacquisition review is worth substantial debate. I don't necessarily feel that it must be the SEC or that it must be FERC or that it must be the states. I do believe that the preacquisition review must be complete and predictable and consistent across different kinds of entrants. I don't mean to suggest that if we—I would be much more inclined to support legislation of this thrust if that particular kind of review were in place. Yes, Senator.

The CHAIRMAN. Well, if you will further yield. As a practical matter, isn't that done now? Before you go to the markets, before the IPPs go to the markets, don't they have to in practice show the approval of the state PUC? Isn't that done now?

Mr. HEMPLING. There certainly, Senator, is an advance review of a sort in the financial community. And I do not mean to denigrate that type of review at all when I assert——

The CHAIRMAN. I am talking about the PUCs.

Mr. HEMPLING. Let me address the PUC review. There is in some states an advance review, but the problem is this. When Mr. Berry discussed the adequacy of state review, he was referring to situations where the entire corporate structure was within one state. And I think you very correctly in a question distinguished when you were discussing the Middle South case the interstate regulatory problem from the in-state regulatory problem.

The concern that I have is that corporate structure is not a single state problem. The types of structures or restructuring that have raised complex issues of multistate regulation today are synonymous with utility restructuring itself, the Middle South case which covered four states, AEP transmission allocation cases which covered seven states, the Utah-Pacific Corp. merger which covered seven states, the issue of the acquisition of Public Service of New Hampshire by Northeast 'Utilities which covered six states. My point is that it is not necessarily within the authority of any particular state to be able to trace in advance the results of corporate structures that may go across many states.

So, I don't criticize or suggest the inadequacy of state review except to say that in a multistate corporate structure which Senate 406 could encourage, there is necessarily a requirement of a federal review.

The CHAIRMAN. Well, I will come back to that. I thank you for yielding.

Mr. BERRY. Mr. Chairman, could I just correct one point, and that is my company operates in Virginia and North Carolina. And we had to have oversight of both states in order to proceed with this process I've just described.

Senator CONRAD. Mr. Chairman, I have one additional question and that goes to the question of undermining PUHCA itself. Obviously, we have this act for a reason. It grew out of a pattern of abuse years ago, and we got as a result a legislative response.

I would like to ask both Mr. Smith and Mr. Berry why shouldn't we be concerned that this undermines PUHCA. And perhaps, Mr. Smith, you would argue we should be concerned that it will do that.

Mr. SMITH. Well, our company, Senator Conrad, is not a registered holding company. So, my experience is not with operation under PUHCA. But I think that certainly the thrust of the amendment is to remove holding company oversight over these independent power generators that otherwise would be under that.

I think it is a matter for the committee to be interested in and concerned about, but very frankly, I am not in a position because

I'm not regulated under that act to talk definitively about the pros and cons of different parts of it.

Senator CONRAD. Mr. Berry, would you give me your analysis of why, and then anyone else, Mr. Kearney?

Mr. BERRY. I think the Holding Company Act was enacted 45 years ago in 1935 to correct some abuses that existed there. We have had a whole body of legislation involving securities transactions and corporate structure since then that probably overlapped in terms of correcting the same abuses.

But, quite frankly, the conditions that we are looking at today of having a competitive marketplace and generation simply didn't exist in 1935. So, it seems to me all we are trying to do is to bring the act up to date, to have it recognize the facts of life as they exist in 1990 as opposed to the facts of life as they existed in 1935.

We are not removing any of the protections that are in the act. Mr. Hempling seemed to be talking about all these protections as if we are talking about repealing the 1935 act. We are talking about a very small change to the act to reflect present day realities.

The CHAIRMAN. If the Senator will further yield.

At the time the PUHCA was enacted, we didn't have the two Federal securities acts. We didn't have the Federal Power Act, or they had just been enacted. The state regulatory law was in its very early stages. All of the protections against self-dealing, issuing of security on invalid or insufficient assets, all that is covered now by these other acts so that I think most people would probably agree without being for this act, that PUHCA is not necessary for the limited purpose of ensuring stable securities and protection against self-dealing and that sort of thing.

Senator CONRAD. Well, don't we have the possibility at least of self-dealing? I mean, we heard assertions this morning from several of the panel members that that was the case. I know for certain, because I have it in my notes, that Mr. Hempling made that assertion.

The CHAIRMAN. Well, that is covered by the Federal Power Act and regulated by FERC, and that is not affected by this.

Mr. HEMPLING. Senator, if I may respond on that point. I suppose it is fair to say this is the largest area of disagreement between those who would like to see new entrants to the market in a certain statutory form and the supporters of Senate 406.

Let me make the argument for why the Holding Company Act is a unique protector, and I can do it by giving you first an example. And this is what many believe is the primary example of the new IPP. It is called The Thousand Springs Project in Nevada where Sierra Pacific Resources, a utility holding company which owns the utility, created a joint venture with construction contractors like Westinghouse, Stone and Webster and others to serve western states and to build eight coal plants over a period of years. The project may be an economically good project. It may be not.

The problem is that the relationship of construction contractors on the project to the buying utilities was one where we wanted an advance examination of those relationships for fear that if we had later rate review, there might not be competitive bench marks because competitors would have bowed out of the market.

There was no Federal Power Act review in advance because it didn't come under what we call section 203 of the Federal Power Act. It wasn't a merger or a transfer of assets. The only advance review that we had with the multistate concern was the Public Utility Holding Company Act in the preacquisition review. Now, there is a dispute between my organization and the SEC in court as to the adequacy of that review, but my point is that that was the review that was available at the time.

We could have waited. If there were no act, the situation would be that we would wait until power supply contracts were signed, and then under the Federal Power Act we would review that those wholesale contracts for their justness and reasonableness. The simple concern is that if competitors are gone by the time we reach the review of the power supply contract, they can't be brought back. And that is precisely why Congress enacted both statutes at once. It is our firm position that they do not duplicate.

Senator CONRAD. Mr. Kearney?

Mr. KEARNEY. Senator Conrad, let me go back to the question of competition and the impact of this particular piece of legislation.

Competition is here today, and we are not going to be able to turn that off. What we are talking about in this legislation is perfecting that competition so that we can eke out the last increment of cost savings. We are not talking about restructuring via this piece of legislation. And if this piece of legislation is not passed, there will continue to be competition, there will be the other producers out there, and the systems will have to address the questions that Scott and Mr. Smith have raised.

This piece of legislation really addresses can we make that process better and more cost effective to consumers. And I think it is a very effective piece of legislation in doing that.

Senator CONRAD. Mr. Chairman, I have taken more than my time. I very much appreciate it. I just want to say I think this is as excellent a panel of witnesses as we have had, and I think you have done an excellent job putting these hearings together.

The CHAIRMAN. Thank you.

Let me call on Senator Wirth, and maybe he will recognize you, Mr. Smith. Mr. Smith was raising his hand.

Mr. SMITH. I would certainly yield to Senator Wirth. I was just going to make one comment if I might with regard to the question of cost. And this was in reply to a question from Senator Nickles I believe from Mr. Kearney.

And I understood Mr. Kearney to say in describing the differences between the cost of an IPP non-regulated plant and a regulated company generating plant that there would be cost advantages in favor of the non-regulate IPP in the area of design and construction and operation. And I have to challenge those, and the record certainly does not support that.

Our company has one of the lowest cost, constructed and operated fossil systems in the country. When you build a plant, there is very little room for difference to design or construct a gas fired turbine one way as opposed to another way. The same is true for small coal fired plants. The utilities normally design redundancy for safety features. It would be possible to take out some of that redundancy for safety features and save that.

Your primary differences in cost are site related and time related, but there is no difference—and you have the same people out there working away building plants that would be owned by regulated companies as by non-regulated companies, the same crafts people. You are going to have the same people essentially designing them. So, there is no cost difference there.

The cost difference, to the extent that there is one—and it's a financing cost difference, and the use of leverage is what enables the IPP to present to the utility and to the regulators and to the world the lower early cost of building and operating the plant. And we think over time that is going to be an illusory difference. We differ on that.

Excuse me, Senator Wirth.

The CHAIRMAN. Senator Wirth has it.

Senator WIRTH. Thank you, Mr. Chairman. I have a number of questions. And I appreciate this panel and again the pursuit of this issue.

First I want to pick to up on the question that was asked by Senator Nickles I think related to the Mississippi Power & Light issue. As I understand that, the problems that occur from that from the perspective of the states—and I guess this is directed at you in particular, Mr. Gray—is that state regulators have lost the authority over wholesale generators and all of the FERC approved costs get passed through. Is that right? Have to be passed through. Is that a general summary?

Mr. GRAY. That's the issue, yes.

Senator WIRTH. Now, what would happen? Could this get resolved if you required the purchasing utilities to file least cost plans with the state PUC?

Mr. GRAY. That would be one way. Well, in the Mississippi case——

Senator WIRTH. What would be the problem in doing that, and would that resolve the problem? And why not do that? Why not take that approach?

Mr. GRAY. The logic of Mississippi itself is that in the multistate system—take a state in the Middle South system, Arkansas. Depending on how the holding company wants to structure its wholesale transactions, the Arkansas Public Service Commission would have absolutely nothing to say about how that power is acquired if it is done through the holding company rather than through the local utility, in which case having the local utility file a least cost plan with the Arkansas Commission would be a pretty futile gesture really. There would be no jurisdiction for Arkansas to really do anything with that plan.

That is the concern, and we are not sure that it is limited to the multistate holding company system. There is no assurance that we have that it wouldn't apply to a——

Senator WIRTH. Then what would be the problem with putting this under state regulatory authority?

Mr. GRAY. That's precisely our point, sir.

Senator WIRTH. And Mr. Kearney said that that really wouldn't cause a problem. Is that right from your perspective?

Mr. KEARNEY. My feeling is that that is being done right now, yes.

Senator WIRTH. Does anybody think that that would cause a problem putting it under, as Mr. Gray is suggesting?

Mr. BERRY. I think it is already under state control.

Senator WIRTH. Well, if it's already under state control if you explicitly state so——

Mr. BERRY. Say so. It doesn't bother us.

Senator WIRTH. Why not just do that? Is there any disagreement about that, Mr. Hempling?

Mr. HEMPLING. Senator, certainly not in principle, but having been a party to many internal industry discussions as to how you phrase the question and what you do in different scenarios where the users of the power on a multistate basis——

Senator WIRTH. We don't have to get into that. We deal in principles and the staff deals with the specifics. Isn't that right? [Laughter.]

Senator WIRTH. Let me jump to the implications for PURPA if I could do that. And I don't know who gets this question. Anybody want to start with it. Maybe, Mr. Berry, you would like to do so.

Should sales be conditioned on all source competitive bidding programs including demand side bidding? That is one way of getting into the PURPA issue, which interests me, as you know.

Mr. BERRY. It is our feeling on the supply side that all source bidding, which gives you the broadest marketplace, is the preferred approach as opposed to limiting the bidders to those who can find somebody to buy some steam or somebody they can give some steam to so that they get their ticket into the marketplace through PURPA. So, we strongly support that it should be all source bidding on the supply side.

When it comes to demand side programs, the approach we take in Virginia and the one that I would recommend is that we consider demand side programs when the state commission considers the need for power, which is the first step in the process whether a utility builds or whether they buy. We think the demand side program should be considered along with the load forecast and the other social issues, equity issues, that are involved in a lot of demand side programs. And the commission should come to its conclusion about whether the demand side programs are adequate, inadequate, cost effective in the need for power determination, and then what remaining need is left after those demand side programs, you do an all source bid on the supply side.

Senator WIRTH. Should that kind of a provision be required in this legislation?

Mr. BERRY. Well, I certainly wouldn't have any objection to that process being required.

Senator WIRTH. We have a formulation laid out by Mr. Berry. I would like to get others of you to comment on it if I might.

Mr. KEARNEY. Senator, I would have no objection to that at all. I think all source bidding is really what is necessary, and I think that that will also answer the question that Mr. Smith raised as to who's cheaper in its production. My advice is come out of the corner. Let's get into the competition and we'll see who is better not only amongst the private power generators, but also the regulated generators should be in that competition.

Senator WIRTH. Is the Berry formulation inconsistent with what is in the Johnston bill now? It's not, is it?

Mr. KEARNEY. Not to understanding, no.

Senator WIRTH. Does that protect the industry that has grown up around PURPA following the—does the Berry proposal protect that industry so we are not driving that away? For environmental reasons, obviously, one of the things we want to do is to continue to encourage that industry and not squeeze it out by having a lot of IPPs come in that might destroy that industry so we end up further behind rather than ahead.

Mr. BERRY. I think the way to consider the impact on the PURPA industry, the cogeneration industry, is that what we have done is to relieve a shackle on them that forces them to do dumb things, forces them to look for uneconomic steam sources. If we pass this bill, they can make a judgment about whether it makes sense to sell waste heat or whether it doesn't make sense.

Senator WIRTH. And they have an 80 megawatt ceiling on what they can do. Right?

Mr. BERRY. No.

Mr. KEARNEY. No.

Mr. GRAY. No.

Mr. BERRY. They can be as big as they want to.

The problem is that a certain percentage of the heat must go to some steam use. And we see some bizarre things like taking that waste heat to produce carbon dioxide and selling it at a loss, selling the steam to an industrial user at less than cost, which means you are paying more for electricity than you need to.

So, what this bill does is get rid of all those aberrations and yet promote cost effective cogeneration because it will be a more efficient way of supplying electricity.

Senator WIRTH. Mr. Hempling?

Mr. HEMPLING. Senator, I think what you have formulated is a significant advance. The problem which remains is the problem of nondiscriminatory transmission access. Let me give you one quick example.

In the Pacific Corp.-Utah Power and Light merger where the FERC ordered the merged company to offer nondiscriminatory transmission access——

Senator WIRTH. I'm going to come to transmission access next, but go ahead.

Mr. HEMPLING. My point is that the PURPA facilities were excluded from the wheeling conditions. And so, the merged company remains able to discriminate against PURPA QFs explicitly by denying them transmission access although the company is required to grant transmission access to others. So, the key point must be that everybody has equal access to the markets.

Senator WIRTH. I am going to come back to the access issue in a little bit.

Mr. Smith, do you want to comment on the Berry formulation?

Mr. SMITH. Yes, two comments if you please, Senator.

With regard to PURPA, the intent of PURPA—and I recall it well because I was probably the industry's principal witness in the House and Senate in 1977 and 1978—was that in order to take maximum advantage of the thermal energy in this country, we should use processed steam from industrial sources to also produce electricity, and you take maximum advantage of that. And where that has happened under PURPA, that has achieved excellent economic efficiencies.

But because of the requirements that only 5 percent of the steam involved had to be used for industrial processes, what sprang up quickly around the country—and there were tremendous excess of this, particularly in California and Texas—were plants that were built not to use industrial processed steam that was otherwise required, but were built in order to sell at high cost into the electric utilities' grid.

And in our testimony we point out that in the situation of Houston Lighting and Power in Texas, Houston Lighting and Power was required to buy cogenerated power at a cost of about $230 per kilowatt versus their own cost of about $35 from a lignite plant from which they would have otherwise produced the power. And their system was adversely impacted by having to pay $150 million more for that amount of energy than they would have had to pay without that extension of PURPA.

So, when you say how has PURPA worked, I think you have to look at each facility and determine whether or not it is an appropriate use of waste processed steam or whether the steam, as Mr. Berry said, was just a contrived ticket to build a facility that probably wasn't needed on the grid to sell at a higher price than the utility could otherwise produce the power.

Senator WIRTH. What is the therefore to that, Mr. Smith?

Mr. SMITH. Therefore, customers are paying higher costs for electricity than they should be paying.

Senator WIRTH. That is descriptive. What is prescriptive from the perspective of this piece of legislation.

Mr. SMITH. From the standpoint of this piece of legislation, as I sought to point out earlier, the practical effect of this legislation I think is going to go far beyond the limited scope that the legislation has been described as being intended to have here. I think you are going to have very innovative entrepreneurs out there, and I think you are going to have consequences that go far beyond the examples that have been discussed here.

And my concern is that in those situations, our companies are going to be paying higher costs for electricity than we otherwise would be paying, and we are going to be prevented from building new baseload capacity in the future.

Senator WIRTH. We have on the table a piece of legislation that has been proposed by Senator Johnston. Now, let's assume that we are moving ahead to mark up this piece of legislation and assume that we are concerned about the PURPA issue and making sure that we are continuing with what are presumably some environmentally positive steps that have come out of PURPA.

We go to you and we say, okay, now, what changes would you suggest be made. Don't describe for us the problem. We have heard the problem. You have done a good job of doing that. What do we do?

Berry put a formulation on the table to try to resolve this issue. What would Smith react to that? Is that a good formulation or not a good formulation? If it is not good, what changes ought to be made?

Mr. SMITH. As Mr. Berry described what I will call his recommendation, it is that the bill be expanded to include a provision requiring all source bidding by utilities. If I misunderstood Mr. Berry, I am sure he'll modify that.

Senator WIRTH. Why don't you give us the two-step Berry formulation again, will you, Mr. Berry?

Mr. SMITH. But that was what I understood.

Senator WIRTH. Let's get the two-step Berry formulation.

Mr. BERRY. It is my feeling that the process to go through—and much of this is a state level process. If you want to mandate it, I guess you have the power to do that—but that the state should have a proceeding where it determines the need for power. And in that proceeding they look at load forecasts and they look at demand side programs and determine whether they are adequate, inadequate or cost effective and approve, disapprove, modify those programs leaving a residual need for power that has to be met on the supply side. Then we should go to the competitive bidding process to meet that supply side need.

Now, I think that is great. I advocate that. That is what we are actually doing in Virginia and it has worked. I'm a little nervous about saying you want to mandate that from the Federal level and take away all the options.

Senator WIRTH. Leave that aside for a minute.

You have heard the basic formulation. Now, do you react to that, Mr. Smith?

Mr. SMITH. I can state my reaction very simply. The states do have the power now to conduct the determination as to whether or not electric plants should be built. The states are closest to the customers and the consumers, and I think that the states should retain that right. I would not favor the Federal Government in this legislation beginning to mandate to the states what sort of load forecasting and need proceedings they should conduct.

Secondly, I certainly would not recommend that all source bidding be prescribed by Congress in legislation of this type because I think as a practical matter that would further make it more difficult for the regulated utilities to build the large amount of baseload capacity that we are going to need in the 1990s and beyond because regardless of how much QF small power, IPP or other nonutility generation we are going to have to serve this country, we are going to have to have large baseload plants built by regulated utilities.

Senator WIRTH. My understanding, Mr. Smith, of what you are really telling us is that you really don't want any change. Right?

Mr. SMITH. As to this bill, we have said that we don't believe that it is wise to enact this legislation, yes. But that is not to say that the world is perfect. That is not to say that we haven't had problems with PURPA.

Mr. McCOLLAM. Senator Wirth, could I comment on this?

Senator WIRTH. Mr. McCollam, please.

Mr. McCOLLAM. I have been very quiet here.

Senator WIRTH. I've noticed that.

Mr. McCollam. You probably can see for a lot of good reasons I've been quiet——

[Laughter.]

The Chairman. You better be careful or we will ask you which side you're on on this. [Laughter.]

Mr. McCollam [continuing]. Because there are honest differences of opinion that are quite evident from this discussion and from the one that took place last week.

But I think I could speak for the industry in saying that we would have a great deal of concern about mandatory competitive bidding, particularly if it is mandated at the Federal level, from the point of view of eliminating managerial discretion which I addressed in my testimony earlier today in my summary of it.

We have taken a look at this question in connection with the FERC NOPRS, and our industry adopted a policy position back in January of 1988 having to do with independent power producers which, in effect, says that utilities should not be required to buy from IPPs. The decision to buy or not to buy must be voluntary, obviously, subject to the type of state regulation we have been talking about here at the hearing this morning. And utilities ought to have the option to build for themselves under traditional regulation or as an IPP on the same basis as other IPPs in or outside of their service territories.

This is the position that the industry has reached a consensus on some time ago. And, therefore, if you mandate competitive bidding at the Federal level, we would have a great deal of concern about the elimination of the type of managerial discretion which we think is necessary in order to meet future needs of our customers.

Senator Wirth. Any other comments on the PURPA issue?

Mr. Kearney. I just would like to emphasize, Senator, that I think that you would see the continued use of efficient cogenerators under this particular piece of legislation and all source bidding simply because where there is an economic benefit to cogenerate—and there will still be a number of those—they will be the most cost effective way for anybody to proceed.

Senator Wirth. You all don't think that all source bidding is as destructive as Mr. Smith thinks it would be, obviously. Right?

Mr. Kearney. Not at all.

Senator Wirth. Let me go to the other issue that we sort of skirted around, and maybe this has been addressed more directly and I have not heard it. But if this is repetitive, let me know. I want to ask somebody to explain in very simple terms the transmission access problem. [Laughter.]

What I would like to do maybe, Mr. Smith, is to have you tell us why it is a problem and then maybe get Mr. Berry or Mr. Kearney to tell us how the problem gets solved or is solved. Is that a fair way to put it, I mean, why it is a problem and then how the problem gets solved? Is that a fair way to do it, Mr. Chairman? Maybe you have already done this.

The Chairman. That's what we are here for.

Senator Wirth. This issue keeps coming up. I see its shadow around on a steady basis. You brought it up very directly, Mr. Hempling. Would you like to——

Mr. Smith. Yes, very much. Thank you, Senator Wirth.

Senator WIRTH. I put that one right down the middle of the plate. I see him standing up there. Right? [Laughter.]

Jose Cansecu of the utility industry. [Laughter.]

Five hundred feet, Mr. Smith. Hit it.

Mr. SMITH. I have swung, but probably not as good a pitcher as I am facing right now.

I think, first of all, very briefly one has to understand that the transmission system is not only integrated and very complex, but that it operates very differently from gas or water or telephone transmission systems, and that while you may seek to transmit power from utility A to utility B through utility C and that utility B may, in fact, pay utility A for the power and utility C for the wheeling, that the power probably won't go over the lines of utility C at all. It will flow through other lines, through other systems, and it is a tremendously complex operation.

And the most important use of transmission and the functions that it serves is to provide and maintain system reliability for the systems and their consumers. So, reliability is a starting point with transmission.

It is also possible to use the transmission system for economic power exchanges. And so, in addition to having the transmission system serve to provide a reliable source of power by tying the utility generating plants together for a number of systems, you can also make limited amounts of economy exchange. And those exchanges take place on a daily basis or what we call a limited or short-term basis or in some cases over a long-term basis. But to the extent that the transmission system is loaded or obligated with economy transactions, that always I think should yield to the reliability of the system.

When one talks about wheeling, I think you have to consider those two aspects, the impact on the reliability of the system and the economics of the wheeling.

The concern about wheeling from the standpoint of reliability is, for example, with cogenerators, IPPs, their economic interests—and this is a legitimate economic interest from their standpoint as they see it—is not focused from the standpoint of maintaining reliability. It is to sell as many kilowatts and as many kilowatt hours as can be sold into the grid.

And one of the questions that has to be resolved on a case-by-case basis is to what extent the cogenerated power or the IPP power is subject to the dispatch of the host utility because it is tremendously important that we not hang or festoon a lot of unregulated small systems around the transmission grid in such a way as to run the risk of interfering with the reliability of that grid to a very, very large area. That is one concern. And people in various systems have discussions, negotiations and debates continually over to what extent the transmission system may or may not accommodate new sources of power.

The second question is an economic question, and that is if a utility system has been planned and built and has billions of dollars invested primarily in large generating plants designed to serve a certain service area over a long period of time, and the costs are fixed and the rates are fixed based upon that, and into that world you introduce a new supplier of electricity which takes revenues away from the regulated system, then obviously you have two effects. You reduce the profitability of the regulated system, its ability to earn its cost of capital.

But secondly—and from the consumer standpoint, this is more important—the costs of that system then have to be shared by fewer users and the costs have to be spread over fewer kilowatts and kilowatt hours. And that substantially raises the cost of service.

As I mentioned earlier, there are utilities in this country where five or six large industrial customers may represent 40 or 50 percent of their load. If that load were subject to bypass, the type of bypass that took place, let's say, in the gas industry, when industries through the pipe were able to bypass the producer contracts with the pipelines and buy directly from a producer at lower price and the pipelines had to wheel it—the pipelines lost their revenues from that. If you have that happening in the electric utility industry, in certain areas you could have tremendous cost increases that the residential and the commercial customers would have to bear because of that bypass.

Now, if you are able to plan your system so that you know that you will or will not have a certain load, then obviously you are going to only invest to serve the load that you expect to have. But if you plan it, regulation approves those plans and you raise billions of dollars and spend those, the capital has been described by some economists as being idiosyncratic. That means, as I understand it, that once those huge blocks of capital are taken and invested and put in facilities in a certain location, they're irrevocably committed to that particular use in that location. It is not like a telephone system where you can buy or sell switches and you can move those around, but once your capital is in place, it is either going to be used as it was planned and intended or it is going to be wasted or other people are going to pay the costs of it.

Senator WIRTH. The three basic problems are complexity, reliability and economics. Is that right?

Mr. SMITH. Yes.

Senator WIRTH. Now, complexity is a problem just because it is very complex. And you all know a lot about it, and Mr. Kearney's operation does not. And you can't depend upon them understanding the complexity of the system to be able to plug into it.

Mr. SMITH. No.

Senator WIRTH. Is that essentially the basis of the complexity argument?

Mr. SMITH. I wouldn't put it that way at all.

Senator WIRTH. What is the root of the complexity argument? We all know that these are very sophisticated, complex systems. Why can't Mr. Kearney's company understand the complexity of the system?

Mr. SMITH. I would expect that his company would understand the complexities of the system. I would say that the economic incentives for his company are different than the economic incentives for the regulated utility. Mr. Kearney's company——

Senator WIRTH. But your first point was technical complexity, wasn't it? Your first point you were making was technical complexity. It is technically complicated. I just want to make sure I understand. Is it more we are going to get economics as the third element?

Mr. Smith. The technical complexity is related both to—it's a preamble to the reliability and to the economics. Technical complexity is not intended to stand alone and separate from reliability——

Senator Wirth. It doesn't stand alone. It's not a technical complexity problem. It's a reliability and an economics problem. Right? So, there isn't a technical complexity problem.

Mr. Smith. The reliability and the economics involve problems of great technical complexity. Technical complexity overrides both, but I think you could divide just as easily into reliability and economics.

Senator Wirth. On reliability, the issue is fundamentally—let me see if this is correct—that you are more reliable. You, the basic utility, are more reliable than an alternative energy source, that they might flake out, they might have a strike, they might have a fire, they might go out of business, they might be economically nonviable in the wintertime, or the guy has high yield bonds and he goes down the chute, or whatever it may be. You are more reliable than they are. The consumer cannot depend upon the competitors to have the kind of reliability to avoid brownouts. Is that the basic issue of reliability?

Mr. Smith. Yes, in the sense that they don't have the public service obligation of reliability that we have. You have a number of these small power producers, wood chip burners that have gone through bankruptcies. Some companies have had to come in and take them over.

Senator Wirth. But that's the basic issue. I understand. That's the basic issue here.

Mr. Smith. They don't have the same obligation of reliability. Under their contracts, they will have obligations spelled out in the contracts for certain performance standards. And their performance will be governed by those contractual provisions rather than the public service obligation that we have.

Senator Wirth. I hear what you're saying. I just want to make sure I understand what the issue is.

The third one is economics. Right? You are arguing, again to try to summarize this, you build a very large system. Right?

Mr. Smith. Yes.

Senator Wirth. That depends upon a certain rate of return. The rate of return is the cost going in and your expected sales on that sort of thing.

Mr. Smith. Yes.

Senator Wirth. And by having that kind of dependable rate of return spread across a very large system and a lot of customers, you keep rates down and keep rates in a reliable fashion. Is that essentially the——

Mr. Smith. Yes, it is.

Senator Wirth. Am I correct in this legislation that this is a piece of legislation that for a utility is voluntary. Is that right? Under the Johnston bill, you don't have to get into this if you don't want to. Is that right?

Mr. Kearney. That's correct.

Senator Wirth. If a utility felt that this would be damaging to that utility, the utility would not have to take advantage of the options in this legislation. Is that not correct?

Mr. Smith. That's exactly the theory, and I think the difference is that we do not believe that in truth and in fact in actual practice it would be purely voluntary. If we felt that it would work to be purely voluntary and that further that it would not lead to wheeling in many areas around the country, we well might not be here in opposition to it. We well might be here in support of it.

But we don't believe in what I'll call the real world of day-to-day utility construction and operation and economics that it would be purely voluntary. We think that there will be tremendous pressures on the utilities and the state commissions to substitute for their own baseload planning and construction arrangements with the independent, nonregulated——

Senator Wirth. But none of that is in the legislation now.

Mr. Smith. It is not in the legislation. And as Senator Johnston has explained, it is not intended, as I understand it, to be anything but voluntary.

Senator Wirth. I just want to make sure that we are talking about what is in the legislation rather than what might be imagined that might come down the line. Washington is full of bogeymen and straw men and red herrings and so on. And I just want to make sure that we are pinning down what are the issues that we can really talk about related to this issue of transmission access.

Let me go to you if I can, Mr. Kearney. Is that fair now, Mr. Smith, to go?

Mr. Smith. Yes.

Senator Wirth. We have complexity as a preamble to reliability and economics. Now, do you want to tell us why what is in this legislation solves these problems, or if it doesn't solve the problems, how the problems that Mr. Smith has can be solved?

Mr. Kearney. That is a tall order.

Senator Wirth. Why? He did the job pretty quickly. He did a pretty good job. [Laughter.]

Mr. Kearney. The issue of transmission goes really beyond this legislation and is being addressed on a number of different fronts.

With regard to the questions that Mr. Smith and the way that he structured his position on it with regard to reliability and economics, in reality the regulated utilities right now are transmitting for all of themselves. There are a lot of bulk transmission activities going on. There are a great deal——

Senator Wirth. Before we get all complicated, you guys have a way of loading an enormous number of words into something that probably can be made a lot simpler than—you all talk to each other all the time. Right? You argue with each other all the time. Right? [Laughter.]

I want to see if we can do this. Let me take Mr. Smith's points. Let's take it from the top.

The technical complexity. You all can understand the technical problems.

Mr. Kearney. Yes, we understand that.

Senator Wirth. Mr. Smith said that, but he then went on to say that that's a preamble to the two other issues. Right?

Mr. KEARNEY. Right.

Senator WIRTH. Now, let me go to the reliability issue. Have there been areas in which non-utility power producers have sold power to utilities?

Mr. KEARNEY. Yes.

Senator WIRTH. Now, has there been an experience that would suggest that there is not a problem with reliability in that?

Mr. KEARNEY. Yes. I don't think—the answer is no. I'm sorry. There have not been experiences that I'm aware of that have indicated that there should be a reliability question. Just to the contrary, there are a lot of examples where we are selling into pools and grids and the electricity is transmitted all over.

Senator WIRTH. Let me ask Mr. Gray on the reliability issue. Now, you all deal with this as the regulators. Right? You obviously don't want to see brownouts from something that you have sanctioned for Mr. Smith's utilities.

Now, have you an experience of independent producers selling into systems that would counter the argument raised by Mr. Smith?

Mr. GRAY. I know of no examples in which third party producers have hurt the reliability of the system.

Senator WIRTH. So, why is the reliability issue brought up?

Mr. GRAY. Well, it is brought up from our perspective because we think it is not really an appropriate issue for this bill. It is an appropriate issue to be decided at the state level fundamentally. And we are concerned that that won't happen, that those decisions will get transmitted to FERC or somewhere else, and the states will be left to clean up the mess afterwards.

I think the states could consider certain reliability issues like should we have only limited or some percentage cap on how much gas fired capacity in case gas prices go through the roof. Are we going to structure our bidding system so that certain markets may have diversity so that there will be a portfolio, for example, of supply? But it seems to me it is an appropriate question for the state commissions to answer.

Senator WIRTH. When you say clean up the mess afterwards, are you suggesting that this would create such a mess that it would be an irresolvable operation?

Mr. GRAY. No, no. What I'm saying is that a couple of years ago the FERC wanted to tell the states how to run their bidding systems. Fortunately, they didn't, but had they done that, it seems to me the states would have been in a much more difficult place trying to fit a Federal solution into what they were trying to do at the state level.

Senator WIRTH. We have beaten the Smith formulation pretty hard here. Let me ask just a final point on this, the economics one, item number 3, that he raised.

Mr. Kearney, now, I would counter that from what I understand, which I will be the first to admit is not an in-depth understanding either of the legislation or of Mr. Smith's problems—but why is not the answer to this problem that this is voluntary and the utility doesn't have to participate if it doesn't want to? Is that the answer to the economics problem?

Mr. KEARNEY. That is the answer to his economics problem. That's correct.

Senator WIRTH. And there are other ones?

Mr. KEARNEY. The way that he formulated that economic issue, that is the answer, that he needn't participate in this. And then under that formulation, he does not have to worry about his economics degrading.

Senator WIRTH. You all have been here for a long time, and I know that my time has expired. There may be others, Mr. Chairman, if we might—I don't know. Mr. Hempling has been trying to get in and Mr. Berry and Mr. McCollam on the subject of transmission access, this issue. Maybe you guys would like to get onto the record on that front, and then I will gracefully bow out, Mr. Chairman.

Mr. Hempling?

Mr. HEMPLING. I will make one statement about complexity, Senator, and one statement about economics.

The issue of complexity is resolved on a daily basis in many parts of the country. What Mr. Smith has not told you is—take simply the example of the Pacific intertie which for years on an hour-by-hour basis dozens of sellers in the northwest and dozens of buyers in the southwest literally transact the day before to decide who will be selling to whom from which plants at what times. An central dispatch person takes care of it, and there has never been a serious mishap. The same kind of complexity is resolved on a daily basis in Georgia and in many other parts of the country. Certainly it is complex, but we have solved many of those problems.

On the issue of economics, the best answer to the utility concerned about so-called bypass is to keep its rates low. If its rates are lower than all competitors, nobody is going to want to leave the system.

Now, if somebody wants to leave the system, I feel certain that regulators are going to not create a stranded investment situation, but require the exiter to pay some kind of exit fee so that the people left behind are left whole. There is no necessary connection between people leaving the system and the ratepayers left behind being worse off.

The simple answer is for the utility to keep its rates competitive.

Senator WIRTH. Mr. McCollam, go ahead.

Mr. MCCOLLAM. Senator Wirth, despite your very noble efforts—and I commend you—to simplify this transmission issue, it is indeed a very complex issue.

Senator WIRTH. Oh, I know. I am just saying, Mr. McCollam, like anything else you could sort of develop principles that you can organize the argument around rather than going from A to Q back to D then to Z.

Mr. MCCOLLAM. Let me try to do that.

We have been talking about really two types of reliability here which I don't think anybody has focused on. There is the reliability of an individual unit like the IPP we are talking about, and there is the whole question of system reliability which is being alluded to here which is far more important than the individual reliability of a unit. I think you can design a unit, you can design the contract, as Mr. Berry has said, so that the individual unit is reliable. How that integrates into the overall system is quite another matter, though, depending on the characteristics of that system.

So, if we get into transmission that is mandated, which is obviously not in this bill, but which has been suggested in various ways by other witnesses, that we have a concern in the utility industry of reliability erosion, system reliability erosion.

Senator WIRTH. That is not in this legislation.

Mr. MCCOLLAM. It is not in the legislation.

Senator WIRTH. Then why are we debating something that is not in the legislation?

Mr. MCCOLLAM. Because there have been suggestions. I sat here last week and heard some of the witnesses suggest that this whole area of transmission is something that ought to be looked at in connection with this legislation. So, I think the potential is there.

The CHAIRMAN. Let me set the record straight. I would oppose looking at an expansion of wheeling in this legislation or otherwise and certainly in this legislation.

Senator WIRTH. Let's remove the red herring from the table. How about that? We are going to move it way over here. It is gone. I just took away.

Mr. MCCOLLAM. The second point has to do with economics, and that is that there is always the potential of imposing additional costs on the utility's native load customers if that transmission system is used for other purposes than serving them for which the transmission system was designed. I don't think you can ignore there. There are basic economic reasons that could adversely affect the native load customers.

And then you have what you call the red herring, the ability to control the entire system from the point of view of reliability, which I think is an issue. Admittedly, it is not included in this legislation.

Senator WIRTH. Mr. Berry, you get the final word.

Mr. BERRY. I have scratched out big pieces of what I wanted to say because you just took the red herring off the table, and I appreciate that.

On the reliability front, we have already had numerous discussions about whether these individual units are going to be reliable. I won't beat that dog to death.

There is the other question of in an electric system where you cannot store energy, you must generate energy at the same instant it is used. So, we have to have very tight control over the level of generation so we match load and generation all the time. We do that with what we call dispatch, and throw economics in it. We call it economic dispatch.

And it is essential that utilities that are responsible for making that match-up in their area are able to control the generation so that it matches the load. They do that by having a computer every fourth second send out a little pulse. That little pulse goes over a telemeter into a turbine and into the governor motor and says either increase or decrease generation. That poor little governor sitting on the front of a GE turbine doesn't know who owns it. So, if it gets a pulse to increase, it is going to increase. If it gets a pulse to decrease, it is going to decrease whether Mr. Kearney owns it or I own it or Mr. Smith owns it.

So, I think we can control the system with these independent generators on there. And I happen to think they are going to be reliable.

But in order to really make it work, we do need to open up a little bit on the excess so that they can come to market. If we tell them, sure, submit your bid and if you are the low cost producer, we'll buy from you, but you can't use the transmission system, I mean, that is just ridiculous. So, we do have to open it up a little.

And the Utility Working Group has submitted a set of principles to FERC on how we can take a couple of steps in the direction of opening access without creating this red herring that we have been trying to avoid. We would point out that if you take one step too many and you step off the cliff, and you're into this morass of cherry-picking and stranded investment and all that sort of stuff. But we think there are a couple of small steps that can be taken and should be taken.

I think the FERC is the logical body to deal with that issue. And so, I think this legislation can go forward just as it is.

Senator WIRTH. In Mr. Gray's terms, we can pass this legislation and then throw the mess to the FERC and the state regulators.

Mr. BERRY. No. I think you could pass this legislation and do nothing with transmission and you'll have an effective marketplace. We have gone out for bids, and we get 10 to 12 times as much offered as we want. So, there is an effective marketplace without opening up the transmission system. We can make some incremental improvements after this legislation is passed or before by opening it up a little bit, but we have to be very careful that we don't step off the cliff.

Senator WIRTH. Mr. Chairman, thank you very much.

The CHAIRMAN. Thank you, Senator Wirth.

On this question of wheeling, I may be confused about my own bill, but I really don't see how this bill has much to do with wheeling. It is wholesale sales. We don't have the kind of situation here where Bonneville Power or something is going to be an IPP and its location, its hydroelectric or something is fixed. You have an IPP who is going to be able to locate within the service territory. Isn't that correct, Mr. Hempling?

Mr. HEMPLING. That is correct, Senator. However, the premise of the bill is to increase competition. The central concern that we have is that utilities freed by the bill to create affiliates, without advanced review for fair competition under the Holding Company Act, will simply be able to favor their affiliates in granting access to transmission.

The CHAIRMAN. How can they favor their affiliates in granting access to transmission if you don't need access transmission to compete?

Mr. HEMPLING. You are precisely correct that if all bidders to supply a plant are in the service territory of the buying utility such that transmission is not necessary to make the market work, then by definition there is no need for transmission authority. But if the concern is to maximize the number of fair competitors as to reap the benefits of interregional efficiencies and interregional competition, then we won't be having bidders located only in the service territory of the buyer, Senator.

The CHAIRMAN. In other words, you have in mind some big plants like a big nuclear plant or something, the 1,200 megawatts, that would need wheeling in order to compete. Is that what you have in mind?

Mr. HEMPLING. Not necessarily, Mr. Chairman. There certainly are small bidders who are located distant or remote, as we say, from the existing service territory. Even in Mr. Berry's example—and I certainly congratulate him on the large number of bidders he attracted—there were bidders from other service territories who could not participate because they could not get wheeling through an intervening utility.

The CHAIRMAN. It seems to me that your argument ought to be that the bill could be made better from your standpoint by granting wheeling. But I don't understand why you would oppose the bill by opening up competition at least to those who could locate within the service territory which is the usual situation in this bill, isn't it?

Mr. HEMPLING. The problem I have, Senator, is I don't know whether over the long term there will be a substantial number of bidders in every utilities' service territory. I just don't know that. The fairness of markets, the level of competition in a market is a function of the number of competitors as well as the market structure in terms of access to essential facilities. If I could be sure that there will always be the number of bidders which economists say are necessary to guarantee a fair market, then I would have no objection to this concept.

The problem is we have to think in my view with a 50 year time line. It has taken 50 years to revisit the statute, and I just can't be sure that we will have that number of——

The CHAIRMAN. Right now, though, you only have in effect the one bidder, the utility.

Mr. HEMPLING. That is correct, and that is why I commend you for opening up the question of adding.

The CHAIRMAN. Isn't it better to have the utility plus whoever wants to come and build a plant within the service territory than—admittedly, that might not include those outside the service territory who can't wheel in—but isn't it better to have some competition than no competition?

Mr. HEMPLING. I agree, but my position remains that there is no way to guarantee it. That will be the result. There is no way to guarantee that the utility and its affiliate will not end up being the only bidders. And even if we do look just in the service territory of——

The CHAIRMAN. Well, they're the only bidder now.

Mr. HEMPLING. That is correct.

The CHAIRMAN. So, what harm have you done?

Mr. HEMPLING. They are still subject to competitive bench marks in nearby regions and in the local area. There are no competitive bench marks, no methods for the state regulators to compare costs of alternatives to the utility's costs.

The CHAIRMAN. Don't they do that now?

Mr. HEMPLING. Only where there are alternatives, Senator. And if alternatives dry up because they cannot get access to transmission, then there will not be the competitive bench marks. You see, even if we had a large number of bidders in the——

The CHAIRMAN. Wait a minute. If alternatives dry up because they cannot get access to transmission, but we have just established that most of them will build within the service territory.

Mr. HEMPLING. That was my next point. I'll accept that assumption for the purposes of argument.

But even if we had all bidders just in the service territory of the buyer, there still are methods by which the utility owner of transmission can discriminate.

Now, if there is a requirement that the terms of transmission are available on identical terms to both the utility's affiliate and the other in-state bidders, then we have made a substantial advance. But as long as there is no statutory authority lodged unambiguously somewhere to ensure that the terms of transmission offered are identical for both the utility affiliate and its in-state competitors, there is no guarantee of fair and permanent competition.

The CHAIRMAN. Well, I think FERC has looked at that issue, haven't they, and stated it as a problem of their concern?

Mr. HEMPLING. They are looking at it at this time.

And if I may extend my answer in one essential respect. The only issue I believe that is before the Congress on the policy level is whether some governmental entity needs to have the duty to order transmission.

The substantial concern that we have is that FERC is frankly gun-shy about its own authority, and it is gun-shy for justifiable reasons. In two well-known cases, one, the Richmond Power and Light case where a utility offered transmission to seller X, but refused it to seller Y, and FERC ordered the utility to extend the transmission terms to seller Y. The court overturned the commission because it said that the commission had ordered wheeling and that was inconsistent with the Federal Power Act.

The CHAIRMAN. Well, it seems to me again that your posture should not be in opposition to this bill, but it ought to be to say from your standpoint that it's a good bill that ought to go further. Is that fair?

Mr. HEMPLING. I am eager to have the debate go further because I think we should add entrants to the market, Senator. But I want to be sure that when we add those entrants, they are permanent fixtures in the market and they have a fair marketplace in which to operate.

The CHAIRMAN. Mr. Smith, you were raising your hand a moment ago.

Mr. SMITH. Yes, sir.

With respect to the issue of transmission and why as much as we would like to send it away as a red herring, it won't go away. It is here.

And this morning I read for the first time the testimony of a Mr. Raymond Lark who is apparently the current chairman of the National Association of State Utility Commissioner Advocates. These are the people who are on the opposite sides of the utilities in the rate cases.

On page 8, he states:

Over the past year, I——

Mr. Lark——

Have cautioned audiences that the PUHCA debate driven by increasing generation sector competition is a structural debate and as such the potential for retail wheeling or bypass necessarily must be explored as a part of it.

There is a speech made by one of the FERC commissioners recently who points to the Transmission Task Force report to FERC as citing an example of where an industrial customer has induced a small municipality to take over a distribution system in order to achieve bypass. The issue of bypass can come out also if a wholesale broker is——

The CHAIRMAN. But they do that under the present law. This bill wouldn't affect that.

Mr. SMITH. Well, it would just accelerate it. You would have more opportunities for that to exist. In other words, the fact that this bill doesn't speak to transmission doesn't exclude transmission being impacted as the actors in the world begin to act our their roles should a bill like this be enacted.

The CHAIRMAN. Now, I think, Mr. Hempling, I understand your position a little better now, and I hope I have stated it correctly that you are really not totally opposed to this. [Laughter.]

Mr. HEMPLING. It depends on what the "this" is, Mr. Chairman. [Laughter.]

The CHAIRMAN. What I have in my mind. [Laughter.]

At least I understand it better I think.

The second thing that really confuses me is NARUC's position. To me the basic debate of this bill when you take all the side issues out—and I think wheeling is a side issue and reliability is an important issue, but it is not central, and leveraging and all those things are not central.

The central issue it seems to me is what someone described as utility management discretion. I think that is the central issue. And I think the question is that this bill might limit utility management discretion by granting to public utility commissions, in effect, the power to—when they have choices, then the utility commissions can, in effect, as Mr. Smith says, require them to make those choices.

If I understand, your position is that if it were purely voluntary, then all these great choices are good, but that you wouldn't be able to perhaps buy a coal fired plant at 1,200 megawatts because you would be afraid the utility commission would say no. You can now buy natural gas at $2 an mcf and you can put it on line and it will be much cheaper per kilowatt hour for the next five years. And the term of office of us utility commissioners will be over by that time, so what the hell. Go the short term instead of the long term. Go the quick fix instead of the reliable one.

It seems to me that that's the central question in this bill. And it is not an easy question, and it is not an easy question because frankly a lot of people don't trust the political process because politicians other than us, of course [laughter] can sometimes be thinking about that next election rather than the public good. It is done all the time, as you well know.

But it seems to me NARUC ought to be wanting more power, and this clearly it seems to me gives power to NARUC. They may want to improve the bill.

Bill McCollam, do you think that's the central question of this bill?

Mr. McCollam. Well, with respect to the NARUC situation, we have taken a look at some of the provisions in their resolution. And we have already addressed a lot of them here in the discussion today in sharing the right of the state commission to review prudence or preserving the right of the state to conduct bidding and provide a right of access to books. Generally speaking, I think there is a consensus that state commissions have all those rights.

When you get into the last part of their resolution that has to do with the integrated multistate utility holding companies, that is a far more complex problem you are dealing with.

The Chairman. That is not what I am talking about. I quite agree that they really have most of these powers that they say they would like clarified.

What I am saying is that it seems to me that the central question this bill poses is whether it is good public policy to have choices available not just to the utility, but choices in effect available to PUCs to force them to take a competitive bid or force them to do some of these things that utility management may not want to do.

Mr. McCollam. I guess I would answer it this way. The state utility commissions already have a lot of discretion in these areas, I guess I would have to say, with or without this bill.

The Chairman. But they don't have the power to order them to buy from an IPP—well, at least not as broadly from an IPP as they do under this bill.

Mr. McCollam. The state utility commissions—and, of course, the laws obviously vary from state to state, but generally speaking they have pretty broad latitude in working with the utilities and influencing them in what their choices would be.

The Chairman. But the bill broadens the choices of utilities, doesn't it?

Mr. McCollam. I don't know that it necessarily does.

The Chairman. Well, a utility cannot have its own IPP now. The number of people who can get into IPPs right now are greatly restricted by PUHCA, aren't they?

Mr. McCollam. Yes.

The Chairman. So, if you are broadening the number of entrants, then don't you broaden the PUCs' discretion?

Mr. McCollam. I think the answer to that again without belaboring the point is the PUCs already have a lot of discretion in the way that they can work with the local utilities in influencing the types of choices they make. I guess I couldn't argue that it probably broadens those choices somewhat. But I guess the central question that has been debated here——

The Chairman. I am not asking you to say which way is the right way to do it. I'm trying just to define what the central question presented by this bill is, and it seems to me that's it. There are those who would argue that utility management is better able to make those choices, is not as influenced by the vagaries of politics in the next election, whereas PUCs are. And contrariwise, the PUCs should argue that their interest is the consumer and the best deal for the consumer, and that certainly it is not in their interest to order non-reliable energy. It seems to me that's the question.

Did I state it correctly, as you understand it?

Mr. McCOLLAM. It seems to me that—I guess I would answer it this way, that it certainly broadens the option, but I think what the real debate is about and where the difference of opinion exists is is the end result of all this good or bad. And you have seen a lot of differences of opinion here that I'm not in a position to address because they are honest differences of opinion in the industry. But it certainly, I would have to admit, broadens the options.

The CHAIRMAN. Did I state the issue correctly?

Mr. SMITH. Senator, I think you stated the issue correctly that it does broaden the option. But I think we have to go further and say on behalf of our position that by broadening the option and presenting an alternative to the construction by utilities of utility owned and operated large baseload plants, the presence of that option in the real world where these decisions are going to be made is going to make it much more difficult in many cases for utilities to be able to get the necessary approvals and authorizations to go forward and build the large baseload——

The CHAIRMAN. That's right. What I am saying is the question is who ought to plan utility construction. You are saying under the present law you have more discretion, and you should have more discretion. And the thing that has me mystified is why NARUC should say, in effect, that we are against this trend.

Mr. GRAY. Can I speak for NARUC on that point?

The CHAIRMAN. Yes, speak for NARUC.

Mr. GRAY. I think why we would like to have the jurisdictional issues resolved is for that very reason——

The CHAIRMAN. I understand that.

Mr. GRAY [continuing]. Is because more options mean more disputes, more incentive for the utilities for disappointed bidders to run to a Federal forum to get a better deal. That is precisely or one of the major considerations that we have here. They have done it on bidding. They have done it on constitutional issues. They have done it on the Grand Gulf situation on the pass-through of wholesale power costs. They did it in the NOPSI case where they went from State court to Federal court. They are continuing, and it is not just electric. It is gas. It is telephone.

If we could get all the lawyers who—you know, the entire utility bars in this room—if we could get them to take a blood oath that they won't sue a State commission in Federal court, maybe we could live with that. But I don't think that is going to happen. [Laughter.]

The CHAIRMAN. I understand. You have a problem now. There is some uncertainty out there, and I think some unfounded uncertainty that the Grand Gulf doctrine is going to be extended to beyond where it is now. But I understand your desire to make that more clear.

But I don't understand your timidity to want to undertake all of these things you want to do which this bill would aid you to do, the least cost planning, the mix of generation, all of those——

Mr. **Gray**. I agree. I agree that the creation of EWGs would give State commissions one additional or a set of additional options to plan the future in conjunction with the utility of how they acquire their supply. It is a question of will that decision stick. Will the utilities and the State Commissions be able to work those out through bidding systems or through other systems within their own jurisdictions looking at the interests of their own ratepayers and make those decisions stick? And I don't think the State Commissions would be well-advised at least by me to take the risk of allowing that kind of entry without having those decisions and those issues resolved so that they know their decisions will stick.

The **Chairman**. Well, as a practical matter, Bill Berry, if you were going to create an IPP and sell to a utility, wouldn't you have to get approval of that PUC before you went to the markets to borrow money?

Mr. **Berry**. You can't finance these projects without State approval. That has been the experience that we have had in Virginia.

The **Chairman**. Is that right?

Mr. **Kearney**. That's absolutely right.

The **Chairman**. Does anybody disagree with that? Do you disagree with that, Mr. Gray?

Mr. **Gray**. No, if the State has jurisdiction over the utility's purchase from that IPP.

I am not sure that is true in every case. It is clearly not true in the multistate registered system depending on how the situation is structured. It may not be true in the multistate system. Your bill would allow EWGs not only to generate power, but to broker power, meaning that you could have a utility acquire an EWG, a stand alone company, very small capacity and turn it into a power broker. It seems to me at that point the question of State jurisdiction may be very murky I guess. You have two wholesale sales at that point.

The **Chairman**. It is very clear that PUC has jurisdiction over the utility, over their rates and, therefore, effectively over this purchase and the prudency of this purchase. Everybody agrees that you are not going to be able to borrow money so the deal will go unless there is this review and approval.

Mr. **Gray**. Again, I guess the question is—I don't put it beyond the minds of our financial wizards to structure a deal where that wouldn't be necessary if this bill were to pass. There could be ways to bypass State jurisdiction. It is happening in a number of forums where we are trying to restructure to avoid State regulation, whether it is by restructuring into a holding company or seeking to transfer our generating capacity to a wholesale subsidiary or something like that. I am not sure that it is necessarily true that in the future the State Commission approval would be necessary for the financing.

The **Chairman**. You see the way this thing plays out—for example, New Orleans City Council has written me on this bill. It says we are against this bill. NARUC is against this bill. They state some of these objections. But to them and I think to most of the companies out there—most of the regulators out there—they regulate, as you know, NOPSI. They see this bill as a restriction on their authority rather than an expansion. It seems to me they are just fundamentally wrong. However you come down on the need to clarify your powers as they exist under the present law, this clearly has to be an expansion of their powers. Isn't it?

Mr. Gray. Well, perhaps I can quote from Commissioner Stalon who is a very strong proponent of third party competitive generation. He said, "For anyone who would like to see increased competition in wholesale market for electric power, it is crucially important the Pike County exception," which is what we are talking about, "hold and be extended. It is very hard to imagine an efficient system of competition where distributing utilities have purchasing rights from a broad set of sources, all of which have prices approved by the FERC in some sense, unless Pike County holds to discipline their purchasing practices." I agree 100 percent with that, and that's the basic point we are looking for here.

The Chairman. Let me ask you a final couple of questions. First, there is this question of ex post facto prudency review. Would you agree with me that local PUCs ought to approve up front—or should they—I won't say you agree with me because I haven't thought it through well enough. But it seems to me basically unfair to let a utility make a decision based upon the best information available at the time and then if the market turns up or down or difficulties come in, TMI or whatever, then to second-guess that decision based on unforseen circumstances. It seems to me PUCs have done that a lot across the country.

Mr. Gray. I think PUCs should have the same legal authority the Congress has given the FERC on this. Section 5 of the Gas Act and section 206 of the Power Act allows the Federal Energy Regulatory Commission to reform contracts.

And the D.C. Circuit has told the commission that it should be looking at using that power with regard to take or pay on the gas side. It seems to me that it is clearly inappropriate to shift all risk of market turning to ratepayers. And if you are not willing to allow contract reformation or post hoc review, that's the result you get. And it seems to me it's a pure policy question of whether in a given case it should or shouldn't be done which is essentially a question of balancing the risks and the financial consequences of the decision.

But I think our members would have a big problem if they were foreclosed from making those post hoc decisions, just as I suspect the D.C. Circuit would be unhappy if the commission refused to exercise that power or provide a reasonable explanation for why it didn't.

The Chairman. Well, I have certainly taken on the role today of defending the bill. And that is not because I have made up my mind, but because I think some of the arguments made against the bill are not the real arguments.

Again, I believe the central question—and we will want to hear more about this in future hearings—is the question of who makes choices. I think that is really fundamental here.

As I understand you, Mr. Smith, you say if we had more choices, that's great if they were purely voluntary, but you don't want to have these choices mandated.

Mr. Smith. Yes, and the availability of the choices, as we have indicated, as we do things the way things are likely to develop, is going to make it much more difficult for us to be able to build the large baseload facilities that we think we will need in the future.

The Chairman. And that is a very, very serious question. We have to protect the right to build baseload plants and to make those long-term decisions in the interest of consumers. We simply have to protect that. And the real question is how is that best done.

Bill Berry says the nuclear plants of the future or the big coal plants of today will more probably be built by IPPs. Obviously, you take a different view.

Mr. Smith. We would disagree because unless you have an assured market for the product of a plant, which is not going to be completed for 6 to 8 to 10 or 12 years, I don't see how you could finance the plant or take the risk.

And I think it is the utility under the regulated system that is going to best provide the assured market. I can see groups of utilities going in together, as has happened in the past, to build new nuclear units. And I can also see the manufacturers of the equipment and the architect-engineers sharing some of the risks just as they did in the early days with their turnkey contracts. So, I can see manufacturers and architect-engineers participating and sharing some of the risk, but I would expect——

The Chairman. But isn't their ability to do so greatly limited by PUHCA?

Mr. Smith. No. I would not see them sharing in the ownership and operation of the plant. I would see them sharing in the risks of the construction costs and the timeliness of completion and other things.

Now, it may be that they will want to build a nuclear plant and go out and seek to do it. But unless you have an assured market for the power from that plant, I would question as to why they would do it. And I don't think you are going to get an assured market for the power unless you are doing it under the regulated system.

Mr. Kearney. But under the regulated system you're assuming an assured market for that power, too. That is the premise on which you build.

I think the key issue, Senator, is that. It is the management discretion. But in Mr. Smith's formulation of that, discretion means the ability to lock us out of the market. He would be perfectly willing, as he indicated, to deal with the current club, the other utilities getting together and building the large plants. Well, we can just as easily do that and are. We have projects that are now under contract for 350 megawatts of baseload coal facilities.

There is no real reason for making that distinction that he makes, and there is a very good reason for expanding the club and allowing us to add one more element of potential cost savings to those that he can also bring to the table as well.

Mr. Smith. I disagree with Mr. Kearney's characterization of my testimony. It is not accurate. There is no club. There is nobody being locked out. I did not testify against a manufacturer or an architect-owner-engineer if they wish to take the risk building and owning and operating anything.

The Chairman. I think that is an appropriate last word. [Laughter.]

Gentlemen, I want to thank you very much. It has really been an outstanding panel. I really do want to commend you. I think we have learned a lot. We haven't come to a conclusion yet, but thank you very much.

[Whereupon, at 12:43 p.m., the hearing was adjourned.]

APPENDIXES

APPENDIX I

Responses to Additional Questions

CMS ENERGY

William T. McCormick, Jr
CHAIRMAN & CEO

January 26, 1990

The Honorable J. Bennett Johnston
Chairman
Committee on Energy & Natural Resources
United States Senate
Washington, DC 20510

ATT: Bill Conway

Dear Chairman Johnston:

Thank you for your letter of December 20, 1989 with the additional questions from Senators McClure and Conrad. I am pleased to respond to these questions. Should you or any other member of your Committee or Staff have further questions, please feel free to contact me.

Thank you again for holding the hearings on your proposed amendment to S. 406. I am grateful for the interest in this important issue expressed by you and your colleagues.

Sincerely,

Bill McCormick

WTM/lrt
Attachment

FAIRLANE PLAZA SOUTH 330 TOWN CENTER DRIVE SUITE 1100 DEARBORN, MICHIGAN 48126 (313) 436-9204

SENATOR CONRAD - QUESTIONS AND ANSWERS

As a general matter, all power projects have risks of varying degree that must be analyzed from a debt and equity viewpoint as well as from the purchasing utility perspective. Each project is unique in a number of areas, such as: technology, fuel source, contract terms and conditions, the price of power, dispatchability of the facility, need for power in the region, cost characteristics of the QF/IPP and various cost components of the purchasing utility in addition to many other risk factors. The issue of financeability of power contracts rests on how these risks are mitigated. Therefore, the responses provided below are based upon financially sound projects where debt and equity investors were able to evaluate the risks of the project and either accept such risks or minimize/eliminate them either contractually or otherwise.

Question

1. The anticipated debt-equity ratios of IPP projects.

Answer

1. Most QFs have debt-equity ratios ranging from 75%/25% to 90%/10%. The higher leveraged projects have secure sales contracts or other mechanisms that make the revenue stream highly certain thus permitting the greater financial leverage. It is assumed that most IPPs will have similar capital structures.

Question

2. Whether such facilities would typically be "project-financed" (i.e., through issuance of debt without recourse to parent companies or other third parties).

Answer

2. It is anticipated that all or a very high percentage of IPPs will be able to be project financed.

Question

3. The term of debt financing for such projects.

Answer

3. The term of senior debt financing for these projects is generally 12-15 years after completion of construction, although in certain circumstances, permanent debt financing may have a final amortization equal to or slightly in advance of the termination date of the power contract. The term

structures mentioned above are for typical power contracts having terms ranging from 15-25 years.

Question

4. Whether such projects can be financed on economic terms without guaranteed purchase or take-or-pay requirements or similar provisions in their power sales contracts which will assure a stable cash flow.

Answer

4. Presently many QF/IPP projects are financed without purchase guarantees or take-or-pay provisions and generally are based upon either availability or deliverability. Contracts based on deliverability are typically called non-dispatchable where the purchasing utility is obligated to pay for all the energy output of the facility. There are no minimum delivery requirements or take-or-pay provisions with this type of contract. Lenders look to the reliability and the deliverability of the plant's output in concluding the financeability of the project.

Contracts based on availability are generally called dispatchable contracts. The purchasing utility is obligated to pay capacity charges based on the capability or availability of the facility to deliver power when the utility wants the capacity not if the facility generates it. If the facility is called on to deliver energy to the utility, such energy payment is based on a negotiated energy charge. Since the utility pays for the availability of the facility, dispatchable power contracts have provisions for minimum daily and/or annual purchases. These provisions are not intended for financing purposes but rather for operational and fuel contract considerations. In addition, fuel contracts generally have minimum take-or-pay provisions which if violated may cause either future reductions in fuel deliveries or significant payment penalties. As indicated previously, these minimum take-or-pay provisions are not required to be paid if the facility is not able to provide the power at these minimum levels. Therefore, dispatchable contracts have certain minimum take-or-pay requirements to match both fuel contracts and operational considerations. If the power contract did not have these provisions, lenders would be subject to significant operational and financial risks which they would not assume.

Question

5. Whether such projects can be financed on economic terms without fuel-cost adjustment or escalator or similar provisions in their power sales contracts which will insulate them from the risk of fuel cost increases.

Answer

5. It is doubtful whether a QF/IPP project can be financed without fuel adjustments or escalator clauses due to the fact that all fuel supply contracts provide for some type of escalation and fuel is often the largest or one of the largest operating costs. Fuel contracts without such provisions or "reopener clauses" could cause the fuel vendor to go bankrupt if even the simplest inflation adjustment was not provided for in the contract. Under this scenario, fuel security provisions in the power contracts would most assuredly be breached during the term of such contract and anticipating this, lenders would be adverse to providing financing to projects of this type.

   It should be noted that utility-owned facilities generally have fuel supplies that escalate in price over time and have no inherent fuel cost advantage, as far as fuel escalation is concerned, when compared to IPPs.

Question

6. What percentage of current Qualifying Facilities have debt-equity ratios exceeding 80-20.

Answer

6. Because most of the current QFs are financed privately, it is very difficult to provide a reasonably accurate response to this question. Most QFs appear to have debt-equity ratios in the 75%/25% range and to lever a project beyond 80% debt would require an extremely strong power contract in an "energy-short" area of the country. The strength of the cash flows from the project and the credit of the purchaser of power would also be significant variables to enable debt ratios in excess of 80%.

Question

7. What percentage of QFs are "project-financed"?

Answer

7. It is estimated that in excess of 90% of all QFs are project financed. Such financing is, however, not a weakness but rather reflects well on the strength of these projects from the perspective of lenders since they believe the projects are sound enough to provide good assurance of debt repayment.

Question

8. The magnitude of the risk premiums (i.e., higher debt and/or equity costs as compared with utilities), if any, that have been required to be paid in order to obtain debt and/or equity financing for existing QFs.

Answer

8. As a general matter, and assuming a good power contract with a financially sound utility, the risk premiums associated with the debt of QFs is in the 50-100 basis point range (i.e., 1/2% to 1%) above the corporate credit rate of the utility purchaser. Obviously this spread could increase for projects where other risk exposures were not mitigated. Normally, these premiums are offset by the higher leverage of the project resulting in an overall cost of capital similar to utilities.

SENATOR McCLURE - QUESTIONS AND ANSWERS

Question

1. Do you support Printed Amendment No. 267 as introduced? If not, what changes would be necessary to secure your support? Please provide the Committee with the statutory language which you would propose to be added.

Answer

1. CMS Energy Corp. and its subsidiaries support PA 267 and submit that it needs no further change. PA 267 adequately responds to the problem of assuring the entry of qualified power generation competitors in the developing wholesale bulk power market. Presently, competitors must meet the severe equity ownership tests of PUHCA or the strict technical definitions as provided by PURPA. These limitations effectively preclude many otherwise worthy projects from competing in the wholesale power business. PA 267 would remedy this problem.

Question

2. Would you support PA 267 if the recommendations of the National Association of Regulatory Utility Commissioners are added? See attached summary page of NARUC testimony.

Answer

2. No, the NARUC statement is in error. There is nothing in PA 267 that would result in Federal preemption or encroachment of existing state's rights and jurisdiction over wholesale electricity transactions. To take NARUC's proposed changes in order:

   - Each state presently has the right to review the prudence of utility wholesale purchase practices in the setting of utility retail rates.

   - We do not agree with NARUC's insistence that Congress preserve the right of state commissions to conduct bidding and least cost planning programs. While some states already have these powers by law, others are not "certificate of need" states and have not statutorily empowered their PUCs with such authority. This should not be addressed by Congress but should be left to the states.

     With regard to NARUC's demands for authority to determine generation mix, fuel mix, technology choice, system reliability, Congress should not approve proposals that would have the effect of putting regulators in the corporate board rooms of utilities. Not only would such an intrusion make corporate decision-making much more difficult (if not impossible), it would compromise regulatory standing when prudence reviews take place. The same concern applies to NARUC's demand that regulators be given authority to restrict or prohibit affiliate transactions and approve or disapprove the transfer of assets from a utility to another party. PA 267 would not alter current federal or state laws that already guard against the concerns of self-dealing raised by NARUC. The demands made by NARUC in its resolution represent an attempt to have the Congress extend authorities of PUCs well beyond that already existing in many states.

- States already have the right of access to the books and records of utilities to review any utility transactions with affiliated or independent suppliers. There is no demonstrated need to federally extend authority to affiliates and parent companies.

- CMS Energy Corp. is not an integrated multi-state holding company and, therefore, would not be affected by NARUC's demand for federal authorization of "regional compacts." In general, however, there appears to be no basis for yet another layer of regulation in an already heavily regulated industry.

Notwithstanding the above comments on NARUC's four proposed changes to PA 267, it is gratifying to note that NARUC does not oppose greater competition in wholesale generation. CMS respectfully suggests that NARUC review the current statutory authority of its state regulatory commission memberships. In addition, Congress should cooperate in this review. We are confident that such review will conclude that no further change in PA 267 is warranted, since adequate legal authority already exists for state and federal regulatory bodies to deal with NARUC's concerns.

Question

3. Would you support PA 267 if a transmission access or a mandatory wheeling provision is added?

Answer

3. No. Adding a mandatory wheeling provision to PA 267 would be ill-advised and inconsistent with the objective of the legislation, which is to encourage voluntary participation in a more competitive wholesale bulk power market. Mandatory wheeling could seriously threaten electric reliability, thereby threatening consumer interests. With regard to other language concerning transmission access, it is unclear what is meant by this. If the intent is to

clarify the authority already existing at the Federal Energy Regulatory Commission (FERC) to implement voluntary transmission agreements freely negotiated among buyers and sellers, such language would be redundant.

Moreover, there is little or no empirical evidence that mandatory wheeling by utilities is necessary or desirable. This is a complex issue that the FERC is examining under its existing statutory authority. Since FERC is likely to address the wholesale transmission issue, it would be unnecessary and premature for Congress to legislate in this area.

Furthermore, substantial variations in terms and conditions of transmission service are likely to be required for individual systems. Electric utilities, their customers and other interested parties should be permitted to tailor specific transmission policies which meet their individual needs. Adequate federal regulatory safeguards exist under the Federal Power Act to insure that the results of such negotiations among utilities and interested parties will be in the overall public interest.

Question

4. PUHCA was enacted to address very serious problems caused by utility holding companies. Is the current absence of abuses evidence that PUHCA has outlived its usefulness, or proof that it continues to work effectively?

Answer

4. PA 267 is not intended to address the general question of whether PUHCA has outlived its usefulness or needs to be repealed. The issue addressed by PA 267 is fairly narrow and applies only to new electric generation facilities, not transmission or distribution facilities. The issue is whether significant statutory disincentives exist to discourage greater competition in the wholesale electricity generation market. It is clear from the hearing record established before the committee that such disincentives need to be removed for future electric capacity demands to be met in a more efficient manner. PA 267 adequately meets this need.

Question

5. What impact would PA 267 have on the structure of the electric utility industry?

Answer

5. The impact of PA 267 would be significant and comparable to the impact of PURPA, which introduced non-utility generation as alternatives to traditional, cost-of-service power plants. PURPA has proven to be an effective source of competition in the wholesale bulk power market. Electricity consumers have, on balance, benefited from the availability of alternative power sources encouraged by the enactment of PURPA. PA 267 would simply expand the availability of these alternative power sources by effectively eliminating the arbitrary limitations on equity ownership and technical configurations that require a steam host under PURPA. These restrictions presently preclude the entry of qualified utility and non-utility competitors into the wholesale power market.

Question

6. What impact would PA 267 have on the price, supply and reliability of electricity?

Answer

6. PA 267 will have a favorable impact on the price, supply and reliability of electricity. It will serve to increase the number of potential competitors seeking to serve new power generation loads. Increasing the number of competitors will generally have positive consequences from the standpoint of price, supply and reliability of electricity since the purchasing utility will have a greater selection of alternative sources of power.

Question

7. A key assumption of PA 267 is that not enough powerplants are now being constructed to meet future power needs. Is that true everywhere, or only in certain states or regions? Do you agree with the assertion made by some that state public utility commissions are primarily to blame for the lack of adequate powerplant construction, or are other factors responsible?

Answer

7. Over the last 10 years electric consumption has increased by approximately 20%. Over the next 10 years it is estimated that electric consumption will increase by 100 GW on 100 major plants. There may be currently different levels of need depending upon location in the U.S., but overall requirements cannot be ignored. Traditional power plant construction is not being undertaken by utilities today because of the breakdown in the regulatory compact referred

to in Answer 4. It serves no current purpose to assign responsibility for this "breakdown" to any one party or group. It is sufficient to say that the nation's need for new electric generation has not been and will not be met under the current regulatory structure. Something needs to be done. PA 267 is a positive step in the right direction.

Question

8. What are your views on allowing utility-owned EWGs to sell power to their utility parent?

Answer

8. If PA 267 were amended to exclude utility-owned EWGs from the list of options available to utility executives, the customers of that utility would be penalized because they would not be assured that all alternatives were considered in the determination of the best power source. As stated in the response above to Question No. 2, there are sufficient regulatory and statutory safeguards presently in place to ensure that a utility-owned EWG would not have any unfair advantage over non-utility sources in any competition to meet power supply needs. This is because ultimately every EWG will still be regulated by the FERC with respect to rates and by the local PUC with respect to the prudency of utility purchase.

Question

9. What are your expectations about how FERC will regulate EWGs? Do you expect that FERC will engage in traditional cost of service regulation, or will it instead allow EWGs to charge "market prices," as has been the direction FERC has recently been heading through a number of case-specific decisions?

Answer

9. This question might be more appropriately addressed to FERC, particularly since only one commissioner remains from the date of issuance of the electricity NOPRs in early 1988. It would be difficult, therefore, to suppose what direction FERC might take on this question. It would appear, however, that the wholesale power industry itself would prefer a market price approach rather than cost of service.

Question

10. Would EWGs be "fuel neutral"?

Answer

10. With regard to fuel source for EWGs, PA 267 avoids discriminating for or against a particular fuel. This fuel neutral approach must be maintained so that all fuel sources will be able to compete openly and fairly for business. Therefore, any decision on fuel source will be made only on business considerations rather than political ones. This is important since each geographic region has its own particular fuel situation.

Question

11. One key issue in the PUHCA reform debate is whether IPPs would have an artificial advantage over utility powerplants due to the tax benefits of debt leveraging. A Committee staff analysis concludes that debt leveraging does not create an unfair advantage for IPPs. What are your views?

Answer

11. Debt leveraging is but one factor in determining the economic viability of an EWG. Other factors include, financial strength of the project sponsors, dispatchability, location, etc. It is the total picture of what constitutes an effective power source that a utility manager must consider in making a power supply decision.

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Mason Willrich
President and Chief
Executive Officer

PG&E
Enterprises

February 8, 1990

Hon. Bennett Johnston
Chairman
Committee on Energy & Natural Resources
United States Senate
Washington, D.C. 20510-6150

Dear Senator Johnston:

Enclosed are my answers, on behalf of Pacific Gas and Electric Company and PG&E Enterprises, to questions received following our testimony before the Committee on Amendment 267 to Sec. 406, the "Competitive Wholesale Electric Generating Act of 1989."

Thank you for providing us with the opportunity to testify before your committee. If we can provide any further assistance, please do not hesitate to ask.

Sincerely yours,

Mason Willrich

MW:mei

RESPONSES TO QUESTIONS OF
SENATOR JAMES A. MCCLURE REGARDING
PRINTED AMENDMENT NO. 267

Question

1. Do you support Printed Amendment No. 267 as introduced? If not, what changes would be necessary to secure your support? Please provide the Committee with the statutory language which you would propose to be added.

Answer

1. We support Printed Amendment (PA) No. 267 as introduced.

Question

2. Would you support PA 267 if the recommendations of the National Association of Regulatory Utility Commissioners are added? See attached summary page of NARUC testimony.

Answer

2. NARUC has suggested that any PUHCA reform contain the following four items:

- First, Congress must ensure the right of each State commission to review the prudence of the wholesale purchasing practices of each distribution utility subject to the State commission's authority.

- Second, Congress must enact specific provisions to preserve the right of each State commission to conduct bidding programs and least cost planning; to determine the appropriate mix of generation, as a matter of fuel and technology choice and as a matter of ownership; to take actions to insure system reliability; to restrict or prohibit affiliate transactions; and to approve or disapprove the transfer of assets from a utility to another party, free from preemption under Federal statutes or the Commerce Clause.

- Third, Congress must provide a right of access, enabling State commissions to review the books and records of holding companies and all holding company subsidiaries, including non-regulated businesses, that transact business with the retail distribution company or EWG entity.

- Fourth, in the case of an integrated multi-state holding company, Congress should authorize regional compacts for those States who have jurisdiction over retail subsidiaries of the holding companies for the sole purpose of regulating the allocation of costs and/or the prudence of wholesale power purchases by the holding company.

The first and fourth items concern clarification of the role of the Federal Energy Regulatory Commission (FERC) and state public service commissions in the regulation of EWGs. We do not believe these provisions should be included in PUHCA legislation. PA 267's purpose is to remove IPPs from PUHCA's stringent registration and exemption requirements. It does not have any other legal or regulatory effect. Therefore, existing regulatory jurisdiction (other than the SEC's under PUHCA) remains unchanged. In fact, the Bill specifically states that Congress is not attempting to preempt or otherwise restrict the prudence of a purchase of electric energy at wholesale or deny the inclusion of the cost of such a purchase and rates subject to such authority.

It is true that the United States Supreme Court decision in the Mississippi Power & Light Company case raised some questions regarding the state and federal jurisdiction. However, we do not believe this complex issue, which involves a myriad of different factual, regional, geographic and regulatory concerns, should be dealt with in legislation.

Any attempt to solve the thorny issue of state regulation of multi-state holding company system purchases in a bill would inevitably lead to uncertainties and litigation and do more mischief than good. Clearly, the more appropriate approach is to include, as is done in the bill, a savings clause preserving the status quo and allowing the issue to be resolved on a case-by-case basis.

NARUC's second point would "preserve" the right of state commissions to conduct bidding programs and perform several other functions, "free from preemption under federal statutes or the Commerce Clause." Many of these items are, directly or indirectly, currently exercised by state commissions. However, specifically listing them and including the "free from preemption" language once again raises the federal/state jurisdiction issue.

Some at NARUC may argue that paragraph 2 is needed to ensure that states are not effectively preempted by FERC from delving into the issues listed in paragraph 2. However, I would predict that very few distribution companies would, based purely on a preemption argument, attempt to avoid state regulation of least cost planning, affiliate transactions, and other such issues. Some distribution companies may argue there is no authority under state law to engage in certain of the oversight powers listed in paragraph 2, but in such a case state legislation would be needed in any case, and, in light of the savings clause, could be enacted without fear that a PUHCA bill would by itself preempt such legislation.

Point 3 would provide right-of-access for state commissions to review the books and records of "holding companies and all holding company subsidiaries, including non-regulated businesses, that transact business with the retail distribution company or EWG entity." We do not believe there is a need to create a separate federal right-of-access to books and records. Public service commissions generally have the right to review the books and records of state regulated utilities and their affiliates in order to prevent cross-subsidy and self-dealing. We recognize the state's right, consistent with its regulatory charter provided under state law, to such access. However, the provision as set forth by NARUC would provide a federal right-of-access without any specific reference to the need for such access to fulfill a public service commission's responsibility under state law to prevent cross-subsidization or self-dealing. Again, this is a matter which can and should be dealt with, to the extent there are any regulatory gaps, by state law, rather than creating an additional federal remedy.

Question

3. Would you support PA 267 if a transmission access or a mandatory wheeling provision is added?

Answer

3. We do not believe that it is necessary or desirable to include a provision regarding transmission access or mandatory wheeling. Our position is based on the fact that PA 267 does not amend the Federal Power Act. That Act includes a requirement that the Federal Energy Regulatory Commission determine the justness and reasonableness of wholesale electric rates. In exercising that authority, the FERC has in several recent cases reviewed whether a deviation from cost-based rates is justified. If the FERC determines in a particular case that an IPP or its affiliated utility exercises market power, it has the statutory right

and ability to ensure that such power is mitigated before approving the proposal. The Act does not diminish this regulatory oversight.

We believe that a combination of FERC and state regulatory control over bidding mechanisms and wholesale IPP electric rates, as well as prudence reviews of utility purchases and current antitrust laws, protect against any abuse of transmission.

Question

4. PUHCA was enacted to address very serious problems caused by utility holding companies. Is the current absence of abuses evidence that PUHCA has outlived its usefulness, or proof that it continues to work effectively?

Answer

4. While PG&E is not a holding company, it is our position that, since the enactment of PUHCA, the electric utility industry and consumer protection legislation has evolved. Accounting standards and practices for utilities have been vastly improved. State regulatory agencies have become sophisticated and maintain close scrutiny of utility operations and functions. Independent financial rating agencies play a significant role in reviewing utility and utility holding company financing. In addition, the evolution of state blue-sky laws and antitrust laws provide significant consumer protections.

In addition, with the exception of allowing holding companies to own EWGs, PA 267 specifically preserves SEC authority over the issuance of securities and other matters related to holding company financing and construction of EWGs.

Question

5. What impact would PA 267 have on the structure of the electric utility industry?

Answer

5. It would provide the legislative framework for an efficient independent power industry to develop in the United States to meet a substantial fraction of our nation's future needs for electric generation. Power purchased from independent produce in a competitive wholesale generation market would effectively

complement power which electric utilities purchase from each other or generate themselves. Without enactment of PA 267, the growth of independent power would be truncated, constrained by PUHCA, and limited to small projects and cogeneration projects which meet the requirements of Qualifying Facilities under the Public Utility Regulatory Policies Act.

Question

6. What impact would PA 267 have on the price, supply and reliability of electricity?

Answer

6. Facilitating independent power development, could result in a larger number of more diverse and competitive wholesale electric generators/suppliers, in conjunction with a least-cost procurement bidding system such as an all source, multi-attribute bidding system, could also result in lower prices, greater fuel and resource diversity, and greater system operating flexibility. Increasing the number of competitive suppliers that can offer to better match a utility's system planning and operational needs should enable the utility to maintain system reliability and minimize its cost of production.

Question

7. A key assumption of PA 267 is that not enough powerplants are now being constructed to meet future power needs. Is that true everywhere, or only in certain states or regions? Do you agree with the assertion made by some that state public utility commissions are primarily to blame for the lack of adequate powerplant construction, or are other factors responsible?

Answer

7. The need for new electric generation capacity in the mid-1990's is widely recognized. For example, the Department of Energy's energy information agency predicts that there will be a need for 72,500 MW of additional capacity by the year 2000, beyond that currently under construction or planned. The North American Electric Reliability Council predicts an additional 73,400 MW of capacity will be needed by 1997.

The need for additional capacity arises sooner in certain regions of the country, such as New England. Regulatory uncertainty regarding cost recovery of utility investment in additional generation plants is a major factor causing utilities to be reluctant to proceed with powerplant construction themselves. However, responses to utility-sponsored competitive bids indicate that there are many firms eager to supply utility needs for additional power.

Question

8. What are your views on allowing utility-owned EWGs to sell power to their utility parent?

Answer

8. While the PG&E-Bechtel Generating Company does not have any current plans to sell power to PG&E, we believe that there should be no absolute prohibition against such sale. Utility customers should not be prevented from receiving the benefits of power purchased from an EWG solely because that EWG has some degree of affiliation with the utility. Issues regarding self-dealing and cross-subsidization should be regulated by state public services commissions as part of their oversight of the local distribution company.

Question

9. What are your expectations about how FERC will regulate EWGs? Do you expect that FERC will engage in traditional cost of service regulation, or will it instead allow EWGs to charge "market prices," as has been the direction FERC has recently been heading through a number of case-specific decisions?

Answer

9. As stated in response to Question 3, PA 267 does not amend the Federal Power Act. That Act includes a requirement that the Federal Energy Regulatory Commission determine the justness and reasonableness of wholesale electric rates. In exercising that authority, we expect that FERC will continue the current trend toward reliance on prices determined through competition in markets where such competition exists, and where the seller lacks market power, subject of course to continuing FERC oversight.

Question

10. Would EWGs be "fuel neutral?"

Answer

10. PA 267 and our concept of EWGs is not related to any particular fuel. To that extent, EWGs are "fuel neutral" --that is, an EWG does not by its nature require or favor one particular type of fuel. Fuel availability, cost, and environmental compliance will generally dictate the type of fuel used.

Question

11. One key issue in the PUHCA reform debate is whether IPPs would have an artificial advantage over utility powerplants due to the tax benefits of debt leveraging. A Committee staff analysis concludes that debt leveraging does not create an unfair advantage for IPPs. What are your views?

Answer

11. We generally agree that debt leveraging does not create unfair advantage for IPPs. While higher degrees of debt leveraging may be obtained by IPPs because all parties to major project agreements share in risks, the term of repayment for this debt is usually shorter than utility bond financing--clearly a disadvantage for the competitiveness of an IPP project. Moreover, when the overall cost of capital of a utility and an independent power producer are compared, any advantage of the independent producer based on higher leverage is diminished.

The recent determination by the Virginia Commission that Virginia Power could more effectively and reasonably provide needed new peaking capacity demonstrates that IPPs do not automatically or inherently have an advantage over utility powerplants.

RESPONSES TO QUESTIONS FROM SENATOR KENT CONRAD REGARDING PRINTED AMENDMENT NO. 267

Question

1. The anticipated debt-equity ratios of IPP projects?

Answer

1. We expect IPP debt ratios to initially be within a range of 70% to 85% of total capitalization.

Question

2. Whether such facilities would typically be "project-financed" (i.e., through issuance of debt without recourse to parent companies or other third parties)?

Answer

2. IPPs will generally be project financed.

Question

3. The term of debt financing for such projects?

Answer

3. Typical repayment terms for our projects are twelve (12) to twenty (20) years.

Question

4. Whether such projects can be financed on economic terms without guaranteed purchase or take-or-pay requirements or similar provisions in their power sales contracts which will assure a stable cash flow?

Answer

4. Lenders and IPP owners are generally comfortable with the operating risks of IPPs but do need reasonable assurance of a market before making an investment. Similarly, utilities that solicit bids for IPP generated power usually are interested in a long-term source of reliable power. Purchasing such with a long-term contract that contains a minimum dispatch or minimum take provision lowers the IPPs cost of capital. A portion of this capital cost savings can be shared with the utility in the form of lower rates.

Question

5. Whether such projects can be financed on economic terms without fuel-cost adjustment or escalator or similar provisions in their power sales contracts which will insulate them from the risk of fuel cost increases?

Answer

5. In general, utilities pass through energy costs to ratepayers. The fuel supply price escalation risk of an IPP does not have to be assumed by the purchaser in a power sales contract in order to finance the project. The fuel supplier or the IPP can assume this risk and factor it into its product cost. The amount of financing available on economic terms will be dependent on how well the IPP has hedged this risk and/or is being compensated for taking it.

Question

6. What percentage of current Qualifying Facilities have debt-equity ratios exceeding 80-20?

Answer

6. We do not have this information.

Question

7. What percentage of QFs are "project-financed?"

Answer

7. We believe that the majority of QFs that are not owned by the host steam user are project financed.

Question

8. The magnitude of risk premiums (i.e., higher debt and/or equity costs as compared with utilities), if any, that have been required to be paid in order to obtain debt and/or equity financing for existing QFs.

Answer

8. The debt and equity risk premiums for existing QFs vary and depend on when they were developed; the qualifications and financial strength of the developer; the constructor and operator; the technology employed; and the contractual and operating attributes of the project.

For QFs currently being developed by well-qualified firms, the debt risk premium is approximately 100 to 200 basis points and the equity risk premium is approximately 300 to 500 basis points over the utility cost of capital. The timing of the development as well as overall financial qualification of the developer are the characteristics of the project that can result in varying degrees of debt and equity risk premiums.

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January 30, 1990

The Honorable J. Bennett Johnston
United States Senate
136 Hart Senate Office Building
Washington, DC 20510

Dear Senator Johnston:

I am pleased to submit the following answers to questions dated December 20, 1989 on PA 267, ***The Competitive Wholesale Generation Act of 1989*** for the printed hearing record. I would again like to thank you for the opportunity to share my views on this extremely important issue. I am available to answer any additional questions and I look forward to working with you in the future.

Sincerely,
Paul J. Elston/NS
Paul J. Elston
Chief Executive Office
Long Lake Energy Corp.

Vice-Chairman
National Independent Energy Producers

cc: The Honorable James McClure
The Honorable Kent Conrad
Bill Conway, Committee on Energy and Natural Resources

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Answers to Senator McClure's Questions

1) Yes, we support both the intent and content of PA 267, ***The Competitive Wholesale Generation Act of 1989***. We believe the nation has much to gain from increased competition in power markets. However, we do not believe that the legislation goes far enough to ensure that truly competitive power markets develop and that consumers reap the benefits of competition. Therefore, we would seek additional regulatory protections to prevent anti-competitive abuses by entities possessing significant market power. (See answer to question #4) We are currently developing statutory language to prevent anti-competitive abuses of market power by entities possessing market power or their affiliates.

2) Yes, we support the principle, advocated by the National Association of Regulatory Utility Commissioners, that to protect retail electricity customers, existing state oversight of wholesale purchases by jurisdictional utilities must be preserved. With regard to the four specific NARUC recommendations:

> a) We strongly support the right of state commission to review the prudence of wholesale power purchases by jurisdictional utilities. However, to promote efficiency for the electricity buyer and seller, and ultimately the consumer, we believe that states should determine the prudence of power purchase contracts at the time those contracts are signed. We believe this would be an improvement over current after-the-fact prudence reviews and more consistent with the nature of the utility/wholesale generator relationship -- and arms-length contract with terms and prices determined competitively.
>
> With the up-front review of prudence of power purchases, regulators will have more information available to them. They will be able to evaluate purchasing decisions against real power supply options. However, the process of before-the-fact prudence review will only benefit consumers if real competition in power supply markets exists.
>
> b) We believe that states currently have all of those rights and that it is not the intent of PA 267 to impinge of those rights. However, we have no objection to language, such as found in part B, reaffirming those rights.
>
> c) We believe that states have a legitimate interest in examining the books and records of holding companies and their subsidiaries which transact business with exempt wholesale generators (EWGs).
>
> However, for the purpose of reviewing books and records, we feel that it is sound public policy to distinguish between truly independent wholesale generators (IWGs) which are not affiliated with regulated utilities and entities which are affiliated with regulated utilities, utility wholesale generators, (UWGs). Clearly, with regard to books and records, states have legitimate consumer and shareholder interests to protect: 1) with IWGs, regulators are concerned about the financial viability of a project; and 2)

with UWGs, in addition to the financial viability of a project, regulators also need to ascertain that captive ratepayers are not subsidizing the construction and operation of the UWG.

Regarding IWGs, to protect ratepayers, the state and utilities have legitimate interests in ascertaining the financial viability of the project at the time a power sales contract is executed to assure that the project will be completed and begin delivering power.

Regarding UWGs, the state has a clear interest in ascertaining the financial viability of the project. In addition, the state has an interest in the ongoing monitoring of transactions between the UWG and its regulated parent or other affiliates to ensure that ratepayer money is not be used to subsidize the construction and operation of the unregulated UWG. Access to these books and record is the primary protection against cross-subsidies.

3) We would support PA 267 if a transmission access or mandatory wheeling provision were included, however we do not believe that generic transmission access is necessary to the development of competitive generation markets. In competitive procurements of capacity to date, suppliers have bid many more megawatts than requested despite the lack of a generic transmission access policy. We believe competition would be enhanced if access to transmission lines were guaranteed, but we recognize it is a complex, political, economic and technical issue in need of thoughtful resolution.

However, at a minimum in the context of competitive generation markets, we believe that transmission should not be used to advantage or disadvantage any potential suppliers. A utility should not be able to use its control of transmission facilities to gain an advantage for itself or any other party or to cause injury to another party in a competitive procurement or contract negotiation for supply of power to a utility.

Tough penalties will deter the abuse of transmission control in competition . Under current law, FERC has limited punitive authority -- FERC may disallow wholesale costs in ratemaking proceedings, or condition approval of rate or corporate structure on the provision of wheeling. These powers are can only be exercised months after the competition takes place and, therefore, offer only limited relief to a party disadvantaged in a competition.

We believe FERC should be granted explicit authority to promulgate and enforce rules to prevent the use of transmission capacity by a utility to gain a competitive advantage in electricity generation markets. In exercising this authority, FERC should place the burden of proof on the owner of the transmission facility, not the party alleging injury. FERC's authority to penalize a utility attempting to abuse its control of transmission facilities should be enhanced and should permit the awarding treble damages for injured parties.

4) PUHCA was intended to protect investors and consumers from the unbridled abuses of market power in the electric utility industry so common prior to its enactment. Clearly, the

drafters of PUHCA could not have anticipated the economic and technological changes that have occurred in power generation since 1935. As it stands, PUHCA represents a formidable barrier to entry into competitive generation markets by entities which lack market power.

However, we believe legislation to afford exemptions to the Act should not weaken the protections for consumers and investors against those who have market power. Without the means to insulate the newly established competitive bulk power markets from anti-competitive behavior by entities possessing significant market power, the goal of increased competition to benefits consumers could quickly be subverted. We believe that adequate protection can be provided in two ways:

a) As PA 267 proposes, leave all other protections in PUHCA in place for entities which do not qualify as EWGs. Companies subject to PUHCA will continue to be bound by its financial and corporate regulation.

b) We also propose that additional regulatory protections against the abuse of market power be incorporated into PA 267. Market power is the ability of buyers or sellers to influence the price of a product it is trading. Clearly, electric utilities have significant market power because: 1) they are able to manipulate the market inside their service territory; and 2) they may be able to cross subsidize both inside and outside their own service territory. In addition, utilities may exercise their market power on behalf of their UWG affiliates to disadvantage competitors and deny consumers the benefits of competition.

To prevent the abuse of market power, we recommend the following be added to PA 267:

PROTECTIONS AGAINST ABUSE OF MARKET POWER

Legislative Language Endorsing Fair Competition.

Congress should strongly endorse the need for fair competition in the electric generation market. There is no explicit reference in PURPA or the Federal Power Act to the desirability of competition in bulk power markets. Congress should also explicitly recognize FERC as having primary responsibility to prevent abuse of market power in wholesale markets and require FERC to exercise its authority through state regulators whenever practical.

Stronger Remedies for Anti-competitive Activities

Congress should mandate that FERC use its authority under Sections 205 and 206 of the Federal Power Act (FPA) to determine that EWGs seeking approval for wholesale rates as "just and reasonable" have not abused market power.

The House of Representatives version of the ***Competitive Wholesale Generation Act of 1989*** (HR 3692) incorporated similar language on transmission, requiring that FERC not accept any rates as "just and reasonable" if a utility uses its market power to advantage an affiliate UWG.

The major shortcoming in FERC's ability to protect against market power abuse under Sections 205 and 206 of the FPA is in the inadequate relief it can offer injured competitors. FERC can refuse to approve an offender's proposed rate, but this is cold comfort to a competitor which has lost out in the bidding month or years earlier. In additional to rate disapproval, the FERC should be empowered to impose penalties on parties who abuse market power. The authority should include the award of treble damages to injured competitors, divestiture, and rescission of the PUHCA exemption

RESTRICTIONS ON UTILITY WHOLESALE GENERATION

In addition, we believe that lawmakers should distinguish between utility affiliated EWGs and non-utility affiliated EWGs. By definition, non-utility EWGs affiliates lack market power and should be excepted from PUHCA without further restriction. On the other hand, UWGs cannot be presumed to be unable to exercise market power to gain a competitive advantage.

The PUHCA exception for UWGs should be restricted to prevent anti-competitive behavior by the UWG or its parent with the following:

S. 406 (the Competitive Wholesale Generation Act of 1989) creates a category of generators exempt from PUHCA called "exempt wholesale generators" or "EWGs". We believe that two categories of EWGs should be established to distinguished between "independent wholesale generators" (IWGs) and "utility affiliated wholesale generators" (UWGs). This distinction would recognize the inherent difference in market power between these two classes of EWGs.

Ownership Limitation

A utility interest in a UWG would be limited to less than fifty percent of the equity or rights to revenues and profits generated by the facility. In a truly competitive market with open access to transmission, there would be no need for ownership limitations. We believe that in the absence of meaningful reform of transmission policy, and in the presence of potential abuse of market power, the concept of an ownership limitation on utilities as a check on potential abuse of monopoly power, first embraced by Congress in the enactment of PURPA, should be applied to the utility ownership of EWGs. Indeed, the 50 percent ownership limitation under PURPA has not prevented vigorous participation by utilities, but has facilitated entry and participation by true independents into generation markets.

In addition, limitations on utility ownership of UWGs could prevent consolidation in the generation industry to the extent it has been seen in airlines since deregulation.

Congress and the public have become increasingly concerned with the harmful effects on competition of concentration of airlines. If utility ownership of a UWG is restricted initially, excessive concentration may be avoided without the need for additional intervention by Congress.

Restriction on Affiliate Sales

A UWG should not be permitted to sell power to an affiliated utility. The prohibition would apply whether the affiliate is located inside or outside the "territory" of the utility. It would also apply to joint ventures between UWGs and unrelated suppliers. The "territory" in which sales are prohibited should be the "reliability region" of the parent as established by the North American Electric Reliability Council. This rule would reduce incentives for self-dealing, cross-subsidies and daisy-chaining and help maintain confidence in the fairness of the competition.

Conversion of Rate-based Facilities

We support the proposal that rate-based facilities may be converted to EWGs if approved by state public service commissions. Such conversions should be permitted only if the entire facility is converted. The risks of cross-subsidy in a hybrid plant which is partially an EWG and partially a rate-based plant could not be controlled. The FERC recognized this problem in its proposed IPP rule when it defined IPPs as "facilities not in a utility's wholesale or retail rate base and not otherwise afforded the assurances of cost recovery." (See Regulations Governing Independent Power Producers, RM88-4-000, at p.35, March 16, 1988)

Organization of UWGs as Separate Subsidiaries

A UWG must be organized as a separate subsidiary of the associated utility, not organized as a division within the utility itself. This separation is necessary to assist state regulators in their monitoring of cross-subsidies and self-dealing by the associated utility. The books and records of UWGs should be available to state regulators to discharge their regulatory duties and prevent the mixture of costs of a UWG subsidiary and its utility parent.

Prevention of Cross-Subsidy

The Securities and Exchange Commission (SEC) has regulations defining and restricting cross-subsidy among subsidiaries of regulated holding companies. FERC should be directed to develop similar restrictions for utility holding companies which own UWGs. Among other potential abuses, UWGs should not be allowed to gain a financing advantage by relying on guarantees from their utility parents. Utilities should be allowed to invest retained earnings in a UWG, but provide no other financial support.

5. Since it is entirely voluntary, PA 267 would have no automatic effect on the structure of the electric utility industry. It would affect the industry only to the extent that utilities and commissions see benefits in enhancing competition. PA 267 enables utility to choose from additional supply options to meet the demand for electricity in their service territory.

PA 267 only seeks to free generators which lack market power to compete to supply utilities with electric capacity from the restrictions of PUHCA. We believe that consumers have much to gain from increased competition in power markets. Among the major benefits to electricity consumers and our national economy from competition are:

- Assurance that an adequate and timely supply of electricity will be available by bringing new providers into the market;
- Continued shifting of construction and operating risks from ratepayers to wholesale generators in a manner that promotes efficiency and penalizes incompetence;
- Increasing the incentives for technological innovation and market responsiveness; and
- Encouraging least-cost pricing through increased supply options for consumers which will reduce cost and increase our national competitiveness. Reliance on market forces, not regulation, to determine prices will optimize the efficiency of the system.

6. PA 267 will likely lower the price of electricity by permitting competition among low-cost suppliers, and increase supply options for utilities by allowing new providers to enter generation markets. The experience under PURPA indicates that competition has led to lower costs for electricity. By the end of 1989, as a result of competitive bid solicitations, utilities signed contracts for nearly 5700 megawatts of capacity. In each of these cases, the utility decision to buy capacity rather than build themselves resulted from their own evaluation that wholesale power purchases would be cheaper.

There are two kinds of reliability: the reliability of the individual plants in the power grid and the reliability and adequacy of the grid to meet demand. PA 267 will not harm either kind of reliability. Over the last ten years, non-utility generators have proven their ability to both construct and operate power plants reliably. Furthermore, utilities which currently have the responsibility to control and maintain system reliability will continue to do so even under PA 267. As the buyers of electricity from wholesale generators, utilities will dictate the terms and conditions of power purchases from these entities.

If anything, the overall reliability of the system should improve as PUHCA restrictions on wholesale generators are lifted. The nation faces a critical shortage of electricity over the next decade unless 100,000 - 150,000 megawatts of new capacity is added. By allowing new entities to compete to supply utilities, we will increase the likelihood that this demand will be met at the lowest cost.

7. The nation needs substantial new generating capacity. The need is particularly acute in some regions of the country. However, with demand for electricity projected to grow at three percent per year, it is only a matter of time before shortages becomes more widespread. Three specific examples:

> a) The Northeast: The Northeast is the region most in need of new capacity immediately. The North American Electric Reliability Council recently stated that the Northeast, " faces critical challenges concerning [generating] resource adequacy during the next decade....In New England, the resource additions required to maintain an adequate future supply [of electricity] are not yet committed."[1]
>
> b) The Northwest: The Northwest was believed until recently to have more than adequate supplies of electricity into the late nineties. However, according to its most recent forecasts, the Bonneville Power Administration, which supplies over 50 percent of electricity to the region, could face a capacity shortage as early as 1991.[2]
>
> c) Texas and Florida: During record cold waves in December 1989, utilities in Texas and Florida found themselves facing peak demands they had not expected to see until the mid - late 1990s. Because they could not meet the demand at times, utilities were forced to institute rolling black-outs.

The impending capacity shortages may be attributed to a combination of developments over the last decade:

> First, we experienced an unusually long period of sustained domestic growth leading to load growth exceeding utilities projections. After years of sluggish growth in demand in the early 1980's, the Department of Energy predicts that the demand for electricity, on average, will grow, on average, 3 percent per year through the year 2000.
>
> Second, these utilities have been reluctant to build new capacity to meet that growth because of: a) regulatory disallowances of construction costs and capacity, b) the financial markets' shaken confidence resulting from the nuclear-cost-overruns, and c) prudence reviews that "second guess" utility capital spending programs.
>
> Third, utilities have cancelled or abandoned approximately 108,500 MW of proposed new capacity since 1980.

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[1] North American Electric Reliability Council, 1989 Reliability Assessment: The Future of the Bulk Electric System Reliability in North America, 1989 - 1998, September 1989, page 14.

[2] Electric Utility Week, ***BPA: Power Surplus Has Evaporated***, December 4, 1989, page 1.

Fourth, with so little new generation being added, the average age of the nation's inventory of powerplants has been increasing and many plants are approaching the end of their useful lives.

In addition, the projected need for new capacity may be understated because of two other developments: first, during the last decade, investments in cheap conservation dampened demand growth. Over the next few years, utilities and their customers will become reluctant to make increasingly costly conservation investments. Second, amendments to the Clean Air Act currently being considered may speed the retirement of old plants and require more investment in new plants.

Clearly, there is plenty of blame to go around, especially if no action is taken to exploit the supply options created by competition. Amending PUHCA to increase competition in generation markets will encourage sensible, efficient capacity additions with the discipline of the market.

8. We believe that utility affiliated UWGs should not be allowed to sell to their parents. Regulators have long recognized that consumers cannot possibly benefit from allowing utilities to sit on both sides of the negotiating table. Permitting self-dealing will discourage competitors because the competition would be stacked against them. Also, utilities may pay an above market price for power to a UWG affiliate or give a competitive advantage to its affiliate to the detriment of consumers.

Competition will only flourish when it both is fair and appears to be fair. In addition, consumers will only benefit where there is arms-length bargaining for power supplies. We believe that a UWG should not be permitted to sell power to an affiliated utility.

9. PA 267 does not require FERC to accept market pricing for electricity in all cases. Under current law, it appears that FERC believes it can accept market-based pricing when it is in the public interest. Based on recent Commission actions, we believe that FERC will only permit market-based pricing when it can clearly be shown that those prices are the result of true competition and that there was no abuse or exercise of market power.

This concept can be formalized in any statute amending PUHCA. The House of Representatives version of the ***Competitive Wholesale Generation Act of 1989*** (HR 3692) incorporated such language, requiring that FERC not accept any rates as "just and reasonable" if a utility uses its market power to advantage an affiliate UWG.

10. Yes, under PA 267 EWGs will be "fuel neutral". First, since purchase from EWGs is totally optional, utilities do not have to buy power from EWGs if would harm the fuel diversity of the utility's generating base. Secondly, EWGs will respond to the needs of the market. Utilities will control the specifications, terms and conditions of competitive procurements. Finally, states which institute resource or least-cost planning will also have a great deal of discretion regarding the fuel mix or resource diversity of the state's capacity portfolio.

11. Yes, we have reviewed the Committee staff analysis and strongly agree with its conclusions. Furthermore, it has been our experience that the cost of capital and the debt-equity ratio for independent facilities reflect the capital markets' assessment of the risk profile of individual projects. Depending on the risk profile, the debt-equity ratio can vary anywhere between 100 percent debt and 100 percent equity. We believe that a market determination of the relative riskiness of projects is preferable and more efficient than a regulatory determination.

Answers to Senator Conrad's Questions

1. The debt-equity ratio of independent power projects is a mechanism for allocating the inherent risk of a project between the debt holder and the owner of the equity. The market is the most effective mechanism to optimize the debt-equity ratio to reduce the cost of capital. I know of examples of projects which are financed with 100 percent debt and other projects financed with 100 percent equity.

Independent power projects typically have debt-equity ratios in the range of 70 - 80 percent debt and 20 - 30 percent equity. These ratios approach the typical ratio for capital intensive large industrial or manufacturing projects. Capital markets determine the debt-equity ratios for independent facilities which optimize the cost of capital for a project.

On the other hand, the amount of leveraging by utilities is administratively determined by regulators, not by the market. These regulators, who may have concerns other than reducing the cost of capital, may insist on a ratio between debt and equity that may be lower than financial markets could bear. Utilities may not be anxious to change that ratio or the total amount of equity in their rate base, since their shareholders earn a regulatorily determined return on equity. Furthermore, when the capital markets evaluate the risks of utility debt or equity, it looks not only at the generation side of the business, but also at the retail distribution side of the business. Because utilities have the statutory obligation to serve customers in their franchise, the markets may assign additional risks to utilities and result in less leveraging. But this evaluation and its results should not affect the decision to build or buy generation.

We believe that it is preferable and more efficient to let capital markets determine optimal debt-equity ratio for a project. In assessing the debt-equity ratio for any given project, the capital markets evaluate three types of risk: regulatory, contractual and operating. For a given project, ownership will not affect those risks. Once completed, a project will operate and produce power for sale no matter who owns it. Over time, as artificial barriers are removed, the debt-equity ratio and the cost of capital for incremental projects, utility or independent, will converge.

2. Most IWGs will likely be project financed through non-recourse debt.

3. The term of debt financing will vary with the nature of the power sales contract. Short-term power sale contracts will likely mean shorter-term debt financing. Long-term power sales contract will likely lead to debt terms for IWGs of 12 - 15 years. Utilities typically borrow for longer terms, corresponding to cost-recovery period of 30 years.

4. The terms and conditions of power sales agreements are defined by the needs of the purchasing utilities. If utilities make good purchasing decisions, ratepayers will benefit. Guaranteed purchase or take or pay provisions do not exist in power sales contracts and clearly are not necessary to finance IWGs. Power sales contract only guarantee payment if electricity or other services, such as peaking or standby service, are delivered.

To meet the requirements of utilities, power sales contracts embrace a wide variety of relationships between buyers and sellers. Contracts may specify energy-only sales. Minimum capacity payments may be appropriate for the purchase of peaking capacity. As with rate-based peaking plants, customers, in this case, pay to maintain an EWG peaker on stand-by to meet peak period demand. In addition, capital markets consider EWGs relatively good investments because they are tangible assets which will produce electricity for sale over a number of years, no matter who owns them.

5. Here again, contracts are based upon the requirements of utilities. We see a mixed bag of contractual arrangements based upon the products and services utilities wish to buy from EWGs. To our knowledge, no contracts exist where EWGs can pass all fuel costs straight through to their utility customers. EWGs may able to, as utilities do through automatic fuel adjustment clauses, index fuel costs to specific fuel market measure.

In addition, utilities may specify fixed priced contracts. In these cases, IPPs can make other provisions to hedge against fuel cost volatility thorough innovative fuel contracting or by acquiring fuel supplies. Finally, some EWGs can sign fixed price contracts, particularly hydro projects and other renewable technologies without significant fuel costs.

6. We cannot give a specific percentage, but from our experience, believe that the majority of QFs have debt-equity ratios in the range of 70 percent debt/30 percent equity to 80 percent debt/20 percent equity.

7. Again, we do not have specific percentages, but believe that most QFs have been project financed. However, the exception is industrial-owned cogeneration which may be financed against corporate credit.

8. We believe that active investors require an 18 - 25 percent after-tax return on equity from QFs. Passive investors in QFs may require 16 -22 percent cash return. The administratively determined return on equity for utilities ranges from 12 - 15 percent of book value.

The risk premium paid by QFs for senior debt is generally 175 - 250 basis points over the treasure note of comparable maturity. This "spread" which reflects a risk profile of a "BB" credit rating , is 50 basis points to 200 basis points greater than the "spreads" over treasury notes paid by utilities, most of which are rated "A"-, with some rate "BBB" - "AA."

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January 19, 1990

Hon. J. Bennett Johnston
Chairman, Committee on Energy and Natural Resources
United States Senate
SH-136 Hart Senate Office Building
Washington, Dc 20510-1802

Re: Competitive Wholesale Electric Generation Act of 1989

Dear Senator Johnston:

Please find enclosed the responses of the Electric Reliability Coalition to the questions set forth in your letter dated December 20, 1989 to witnesses who testified before the Committee on October 9 and 16, 1989. These responses are submitted on behalf of Messrs. Richard Brooks, A. Drue Jennings, Joseph Paquette, and Sherwood Smith, some of whom may submit additional views. We respectfully request that the enclosed responses be included in the hearing record.

Respectfully submitted,

Duane A. Siler

Duane A. Siler
Counsel for Electric Reliability
Coalition

cc (w/enc): William Conway, Esq.

RESPONSES OF ELECTRIC RELIABILITY COALITION TO QUESTIONS REGARDING COMPETITIVE WHOLESALE ELECTRIC GENERATION ACT OF 1989

A. Questions of Senator McClure

1. Do you support Printed Amendment No. 267 as introduced? If not, what changes would be necessary to secure your support? Please provide the Committee with the statutory language which you would propose to be added.

Response: The Electric Reliability Coalition (ERC) does not support Printed Amendment No. 267 as introduced, nor does it envision changes to the amendment that would secure such support. The bill would encourage the development of unregulated Exempt Wholesale Generators (EWGs) by exempting them from regulation under PUHCA. To change the structure of the electric power industry in this way is potentially so harmful to electricity consumers and to the nation's supply of electric power that ERC must oppose the concept itself. That concept can only result in reduced reliability and long term higher costs. ERC does not regard consensus on an amended bill as a realistic possibility.

2. Would you support PA 267 if the recommendations of the National Association of Regulatory Utility Commissioners are added? See attached summary of NARUC testimony.

Response: ERC would not support the bill, with or without the NARUC amendments. Indeed, at least some of the NARUC amendments could reinforce the detrimental effect of PA 267 on franchised utilities' ability to determine what mix of self-generated and purchased power will best serve their customers in terms of continued reliable service at least cost.

A major purpose of these amendments apparently is to give state commissions the primary role in determining whether and under what conditions regulated utilities would have to purchase wholesale electric power from EWGs. Thus, NARUC seeks, inter alia, an amendment that would:

> preserve the right of each State commission to conduct bidding programs and least cost planning; to determine the appropriate mix of generation, as a matter of fuel and technology choice and as a matter of ownership . . . .

As explained in ERC's prior written testimony and the accompanying economic study, the outcome of such bidding programs is virtually a foregone conclusion. That is, a "competitive" bidding program, while superficially neutral, is likely to be strongly biased in favor of non-utility EWG bidders. Due to leveraged financing and resultant artificial cost-of-capital advantages, EWGs can be expected routinely to underbid utilities in "competitive" contests. Lacking any inherent competitive advantages over utility generation, EWGs will be able to offer power at apparently lower cost by shifting certain risks and costs to purchasing utilities. For example, under all known EWG financing scenarios, the utility will be expected to assume market and fuel cost risks, as reflected in take-or-pay contracts with fuel cost escalator provisions.[1]

It is increasingly clear that institutions which rate electric utilities' credit will treat these contract obligations as utility debt. Rating services therefore are likely to require greater equity for, or downgrade the credit rating of, any utility that assumes significant take-or-pay, fuel cost escalator, or similar contractual obligations associated with EWG contracts. An increase in a utility's equity, or a reduction in its credit rating, necessarily increases its cost of obtaining funds to meet future requirements, thereby increasing the cost of service to the utility's ratepayers.

Unless these costs are fully allocated to EWG bidders at the time bids are evaluated, the bidding process cannot achieve a true least-cost outcome. Unfortunately, even assuming that a state commission is prepared to recognize such costs in theory, their quantification will present great practical difficulties. For this reason, the "competitive" bidding process that NARUC seeks to protect will be fraught with error and is all too likely to produce regulatory decisions requiring utilities to purchase EWG power on the basis of illusory cost advantages.[2]

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[1] Testimony presented by proponents of PA 267, as well as subsequent interviews with leading investment banking houses, have confirmed that EWGs are expected to be financed with at least 80 percent debt, and that this financing will be possible only because the debt will effectively be secured with take-or-pay capacity contracts with the purchasing utility. None of the EWG financing specialists interviewed believes that such projects are financible without such take-or-pay guarantees by the purchasing utility, and most regard as equally essential the utility's underwriting of at least part of future increases in fuel costs as well. See answer to Question 11 below.

NARUC also seeks to guarantee legislatively a state commission's right to "review the prudence of the wholesale purchasing practices" of utilities under its jurisdiction. This amendment does not improve the bill. Rather, the amendment creates for utilities that utilize EWG power the same specter of cost disallowance that has characterized some state commissions' treatment of utility capital investment in recent years, already a chronic source of friction in some jurisdictions.

Such reviews would present unique new dilemmas for utilities precisely because their contracts with IPPs will almost certainly have to contain take-or-pay and/or fuel cost escalator provisions, both of which are specifically designed to shift to the utility certain risks which may later show up as increased costs. If these risks, and the associated costs to the ratepayer, later materialize, it would be all too easy for state regulators to second guess the original decision to contract for EWG power. For example, purchased capacity may cease to be necessary in the face of lower demand, or may later become available at cheaper prices from other sources. Or energy may become available from generators whose fuel costs have not escalated as much as those of the EWG with which the utility has contracted.

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[2] Interviews with a number of electric utility credit rating services confirm that utilities which enter into such take-or-pay obligations will have additional debt imputed to their balance sheets, resulting in higher financing costs for the affected utility's future debt. However, our research also indicates that no clear methodology is available for a state commission to use in quantifying in advance the precise cost to the utility of entering into the required take-or-pay contract. As a result, it will be extremely problematic for a state commission to fairly and accurately allocate actual costs to an EWG's bid price, even though it is known with a high degree of certainty that such costs will be incurred. See answer to Question 5 below.

Disallowance of some or all of a utility's costs under a contract with an EWG previously approved by a state commission would be highly unfair to the utility. The inequity would be even greater if the utility's original decision to contract for EWG power was not voluntary. In light of this prospect, ERC believes it would be better legislative policy to prohibit after-the-fact prudency reviews of wholesale power purchases from EWGs.

3. Would you support PA 267 if a transmission access or mandatory wheeling provision is added?

Response: ERC does not support the concept of mandated third-party access to any utility's system for the purpose of transmitting or distributing power not generated by that utility. Such access will significantly increase electric costs for most consumers and adversely affect the reliability of electric service.

If transmission lines become akin to common carriers over which large industrial users can bypass local utilities and wheel power from EWGs, most consumers will suffer. If a select few large electric users choose to bypass the utility's system and import their own power, the remaining captive customers must pay a greater percentage of the fixed cost for the utility's generation and transmission systems.

There are also technical constraints which make the concept of transmission access objectionable. Electric transmission systems traditionally have been designed almost exclusively for two purposes: (1) to transmit electricity from a utility's generating facilities to a single load center that is typically in the utility's service territory; and (2) to interconnect with neighboring utilities to facilitate transfers of power to promote system reliability and economic exchanges. The inclusion of large amounts of unregulated power in these transmission systems could present a wide array of technical problems that would jeopardize system reliability.

Consequently, adding provisions regarding transmission access or wheeling to PA 267 would only increase the Coalition's opposition to the bill. Of course, we recognize that transmission access is an extremely complex issue, and has been the subject of intensive review by the Department of Energy, the Federal Energy Regulatory Commission, the Edison Electric Institute and other industry associations, as well as of debate within the academic and consulting communities. However, we do not anticipate that any new analyses or information will emerge to affect ERC's and its members' opposition to any legislation or rulemaking that would in any way infringe upon utilities' discretion whether, and under what conditions, to allow transmission access to their systems or facilities. Such discretion, in our judgment, is essential to every utility's ability to meet its obligation to provide reliable service, at reasonable cost to the consumer.

4. PUHCA was enacted to address very serious problems caused by utility holding companies. Is the current absence of abuses evidence that PUHCA has outlived its usefulness, or proof that it continues to work effectively?

Response: The current absence of abuses of the type associated with utility holding companies prior to the 1930s is the product of historical evolution and reflects a combination of factors. Most of the conditions that gave rise to PUHCA no longer exist. This is not to say, however, that the Holding Company Act has outlived its usefulness.

PUHCA was enacted in a specific historical context. The Holding Company Act, together with the Securities Act of 1933 and the Securities and Exchange Act of 1934, were responses to unique excesses. These excesses emerged from a climate of pervasive laissez faire about a wide range of business practices, especially those relating to investment and financial activities and to the issuance of securities. In the absence of effective federal or state regulation, many companies (including some utility holding companies) exhibited a type of business ethic rarely witnessed in modern, responsibly managed corporations.

By contrast, today there is pervasive governmental regulation of the kinds of activities that gave rise to the abuses of the 1930s. The SEC effectively regulates the securities-related activities of all corporations, including public utilities and their holding companies, under the 1933 and 1934 Acts. More important, virtually all states now have strong public utility commissions that tightly regulate the electric utilities under their jurisdiction and closely scrutinize their costs and rates. It is highly unlikely that, in the face of this degree of regulation at the state level, utility self-dealing schemes like those witnessed prior to PUHCA's enactment could arise today.

However, the fact that the historical factors that necessitated PUCHA are largely superseded does not mean that its partial (or total) repeal is in the national interest. PA 267 would make piecemeal amendments to PUHCA in order to eliminate SEC regulation for some favored companies, i.e., EWGs and their owners, but not for the traditional regulated holding companies. Paradoxically, under this bill, registered holding companies that have conformed to PUHCA's requirements for many years would be rewarded by continued full regulation, while an entirely new crop of IPP developers would receive complete freedom from PUHCA's strictures, despite having no track record as to their business and financial practices. It is particularly important to note that, while utility regulation has evolved to provide consumer protections similar to those contained in the

PUHCA, this regulation would not be applicable to non-utility EWGs. Thus, PA 267 would eliminate PUHCA protections against abusive practices by non-utility entities which would not be otherwise adequately constrained. In any event, ERC does not support either the amendment or elimination of PUHCA in the context of an effort to restructure the utility industry, and strongly opposes exempting from regulation the very entities most likely to be characterized by the abuses PUHCA was enacted to address.

5. What impact would PA 267 have on the structure of the electric utility industry?

Response: The effect of passage of PA 267 on the structure of the electric utility industry would be dramatic over the long term. Utilities would lose their ability to meet their statutory obligation to serve the electric consumer as reliance on unregulated suppliers increases. Contractual arrangements between the utility and the EWG cannot sufficiently replace the control of supplies necessary to meet the obligation to serve. Economic dispatch of units will generally disappear as take-or-pay contracts are signed. False economics, rather than reliability, will reign supreme.

Utility management decision-making on planning, dispatch and other operational matters will be diluted by regulatory and legal mandate. Service reliability will be seriously eroded by this resulting loss of management control and price to the consumer will increase due to, among other things, the utility's inability to efficiently plan and dispatch and due to the increased cost-of-capital for the utility.

Regulatory review of prudence of contracts with EWGs will replace current prudence reviews of utility-owned generation, with an added layer of court proceedings regarding contract interpretation and enforcement. Regulatory concerns which gave rise to this amendment will not be resolved, only magnified.

In effect, passage of PA 267 will result in a disaggregation of the electric utility industry at considerable cost to the consumer, with no apparent benefit.

The increased forced reliance on EWGs will likely occur as follows:

1.) Passage of the amendment will remove PUHCA's constraints on EWG development. EWGs will offer power based on long-term take or pay contracts with fuel cost escalator clauses. These contracts will shift virtually all of the risk from the EWG to the purchasing utility. Financial and operating risk likewise will be shifted to the purchasing utility. Construction risk will be shifted to the constructor via turnkey contracts, or may be shifted to the utility in larger projects.

2.) Because of the risk shifting, the EWG will be able to achieve non-recourse, project based financing at very high levels of debt with interest rates only slightly higher than the rates available to an investor owned utility (IOU). (As explained in the response to Question 11 below, the EWG's lenders probably will require a small risk premium reflecting the EWG's reliance on a contract to assure its income stream; however, the risk premium is dwarfed by the EWG's ability to utilize a very high debt-equity ratio.) The reason the EWG will be able to heavily leverage at relatively attractive interest rates is that the risk shifting will result in an imputation by rating agencies of EWG debt to the purchasing utility -- the utility will be the guarantor of the debt. Thus, the tax advantage of debt will afford a substantial artificial cost-of-capital advantage to the EWG which is achieved only by imposing an offsetting cost-of-capital detriment onto the purchasing utility. Due to leveraging, the EWG cost-of-capital will be 20 to 30 percent lower than that for an IOU contemplating a similar investment (even including a small risk premium for the EWG debt).

3.) Due to the cost-of-capital advantage, an EWG has the potential to bid a price 5 to 10 percent lower per kilowatt hour than an IOU. (In reality, the EWG will probably bid just low enough to beat the IOU and thereby offer extra-normal rates of return to EWG equity holders.)

The potential 5 to 10 percent per kilowatt price advantage will only exist because proper accounting is not made of the real costs imposed on the utility and/or ratepayers by the EWG. For instance, new capital costs will be imposed on the purchasing utility due to degradation of debt rating and/or a requirement for greater equity in the utility's capital structure. This will result in higher real costs when the utility must enter the financial markets for any purpose, including maintenance investment for transmission and distribution systems. In addition, real costs will be imposed on the utility in the reliability area. The purchasing utility will have to build in additional redundancy for frequency control, voltage regulation and spinning reserves and may have to increase its reserve margins. Further costs will be imposed on the utility because take-or-pay contracts negate economic dispatch and contract enforcement costs will be substantial.

4.) The apparent lower price of EWG power will appear very attractive to state regulators. IOUs will be compelled to use EWG power due to fear of ex post facto rulings of imprudency if the IOU had opted to build its own generating capacity.

The EWG power will appear cheaper because the real costs imposed on the utility will not be adequately recognized in bidding considerations. These are highly complex matters and the rating agencies are now in the process of attempting to quantify these costs. Two factors will result in less than full accounting of the costs imposed on purchasing utilities by EWGs. First, for the foreseeable future, information on these costs will be less than perfect. Although the costs are very real, and recognized by all of the rating agencies and many financial analysts, they are difficult to quantify and

> will remain subjective. Thus, it will be difficult for regulators to empirically determine these costs and add them to the per kilowatt hour price of EWG power. Glen McIsaac of Energy Management Associates, has conducted a survey of existing bidding systems. He notes that "[n]one of the evaluation procedures in the bidding systems reviewed explicitly recognize the financial risks associated with commitments to purchase power from IPPs. Instead, the prices bid by independent suppliers are directly compared to the costs of traditionally financed utility construction."[3/]
>
> Second, within the planning horizon of the regulator, the incentive structure of the rate making process may encourage the regulator to ignore such costs. EWG power will appear attractive immediately, while the resultant capital cost increases may only have to be considered a year or two later. Even then, regulators may feel a political imperative to preserve the appearance of "cheaper" power through disallowance of these or other increased costs. While short-sighted observers might welcome the resulting transfer of wealth from shareholders to ratepayers, the inevitable longer-term effect would be to create yet another disincentive for IOUs to invest in baseload capacity.

6. What impact would PA 267 have on the price, supply and reliability of electricity?

Response: If utilities are compelled (or elect) to purchase EWG power due to its apparently lower price, it is clear that electricity will be more expensive in the mid-term and over the long haul, as the alleged savings are overcome by increases in utility operating costs and cost-of-capital, and reliability will be diminished.

IOUs using large amounts of EWG power will incur higher capital costs. Thus, the normal year to year investment that is

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[3/] Glenn P. McIsaac, "IPP Financing Advantages: Separating Fact from Fiction" unpublished, p 12-4 required to upgrade generator facilities, update, replace, and expand transmission and distribution systems and for other purposes will be significantly more expensive. These new costs, which most likely would have received insufficient weight in the decision to use EWG power, either must be recovered by the IOU or they will reduce the amount the utility can invest in the new and replacement facilities necessary to maintain reliable service. Further, IOUs purchasing EWG power will no longer be able to dispatch on an economic basis because of the inevitable take-or-pay obligations in the EWGs' power sales contracts. This is a prime example of the loss of economies that the purchasing utility will incur and which, while hard to quantify, are highly foreseeable.

In addition, utilities that utilize EWG power will have to increase redundancy in operations, increase reserve margins, and assume most of the costs associated with essential technical items. To provide least cost and reliable service, a utility must have complete control over the siting, design and operation of generating units. The introduction of EWG power can only result in diminished control.

Utilities, constrained by a statutory obligation to serve, build considerable redundancy into their plants. EWGs will have an incentive to lessen their costs associated with redundancy. That is, the EWG developer will seek to minimize capital investments, including investment in redundant components needed for maximum reliability. It will then be the purchasing utility's responsibility to provide the required redundancy by other, more costly, means. For the same reason, the EWG will have no economic interest in providing the reserves, voltage control and other services needed for reliable service, and the utility will have to provide them itself, at greater cost.[4]

Finally, utilities that purchase EWG power will inevitably incur very substantial added costs to enforce extremely complex contracts with EWGs through litigation or arbitration. Disputes will arise about issues ranging from the obligation of the EWG to perform maintenance at prescribed times to the EWG's invocation of force majeure to interrupt or terminate service for economic reasons. Each will have to be resolved by legal means, at great cost. All these additional costs will also be reflected in electricity prices.

> 7. A key assumption of PA 267 is that not enough powerplants are now being constructed to meet future power needs. Is that true everywhere, or only in certain states or regions? Do you agree with the assertion made by some that state public utility commissions are primarily to blame for the lack of adequate powerplant construction, or are other factors responsible?

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[4] Coordination is essential for reliability. It is not that coordination is technically infeasible for EWG/IOU combinations. It is that conflicting economic incentives make coordination extremely difficult. One major utility credit rating agency assumes that IPP power is inherently less reliable. This agency requires IOUs that rely heavily on independent power to increase reserve margins or risk bond rating degradation.

Response:

A. Adequacy of Supply: Whether the nation as a whole will have sufficient electric generating capacity under current planning scenarios, and for how long, are matters of ongoing debate. What is clear is that there is no evidence of an impending national shortfall adequate to justify a radical restructuring of the electric power industry. Predicted shortages of electric power are a regional, not a national, problem.

Most regions of the country are not forecasted to experience shortages. Similarly, the reluctance on the part of a minority of utilities to construct new generation due to past regulatory practices is a regional phenomenon. Indeed, in many regions opponents of utilities' efforts to recover investments in new generating plants have argued, and continue to argue, that generating capacity is excessive. Are utilities now to be whipsawed by allegations of overbuilding coupled with claims that they have failed to construct needed capacity?

The regional aspects of these two concerns (which give rise to PA 267) raise two significant points:

> a. To the extent that state regulatory practices have discouraged utility power plant construction, those practices by those state regulators should be addressed at the state level. PA 267 does not and cannot address the state regulatory problem.
>
> b. The concerns are regional. To impose sweeping mandates at the federal level to address regional problems in a few states is wholly inappropriate and will result in severe and irreversible damage to the electric supply in

> most regions of the nation where the current system is working well.

Evidence of a national shortfall of generating capaciaty in the 1990s is far from conclusive. On the one hand, the Energy Information Administration, citing recent increases in the rate of peak demand growth due to the transitory effects of unusually hot summers in 1987 and 1988 and the effects of strong economic growth, projects electricity sales will increase at an annual rate of 2.6% between 1988 and 2000. EIA Annual Energy Outlook 1989 at 23-25.Id. at 25.[5/] Under the EIA scenario, industry observers have projected that total demand would exceed projected available generation capability on a nationwide basis in approximately 1994. See, e.g., United States Energy Association, 3rd Annual Assessment of United States Energy Policy and Prospects (April 1989) at 6, Chart 9.[6/]

[5/] EIA's projection assumes a growth rate of 2.7% in the commercial sector, driven by a continued "large expansion in commercial activity," and a growth rate of 3.2% in the industrial sector, due to world wide economic growth and resulting demand for products of electricity-intensive U.S. industries. Id. at 25. Obviously, less robust economic growth in either sector would render these projections inaccurate.

[6/] The "normal" growth rate in recent times appears substantially less than 2.6% per year. Thus, electricity demand increased at a rate of only about 1.9% annually between 1980 and 1986. EIA Annual Report 1989 at 24. Assuming a return to this pattern of demand growth, as a result of deceleration of economic growth and/or increased electricity prices, peak demand nationally would not exceed projected capacity until 1999. USEA, 3rd Annual Assessment at 6, Chart 9.

However, EIA itself concedes that utilities face "uncertain demand growth." Annual Energy Outlook at 23. Indeed, there is already reason to believe that EIA's projection, which was released in early 1989, is too high. According to officials of the North American Reliability Council, peak summer demand in 1989 was 1.5% below that of 1988 and fell below NERC's projections.

Looking to the longer term, NERC's most recent 10-year assessment forecasts average annual summer peak demand growth in the United States of only 2.0% over the period 1989-1998. NERC 1989 Reliability Assessment (September 1989) at 10-11, Table 2, Figure 1. This projection is based on actual forecasts made by the utilities that make up the nine Regional Reliability Councils. While NERC cautions that this is a probabilistic estimate,[7/] it places the odds of annual growth exceeding 2.5% (EIA predicts 2.6%) at no greater than 1 in 10. Id. at 11-12, Figure 1.

Under NERC's base case projection of annual load growth of 2.0%, "projected available resources" in the United States will

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[7/] According to NERC's projections, there is a 50% chance that this 2.0% rate will be exceeded and a 50% chance that the forecast will not be reached. Id. at 11. Thus, the 2.0% rate is the most probable of all rates.

fully meet demand until 1998.[8] Id. at 21, Figure 8. Of course, NERC also recognizes that there is a 10% chance that growth rates will approximate those projected by EIA, with a resulting shortfall of capacity by 1993 in the United States. However, NERC states that: "Short lead time capacity . . . could be an option for the 10% probable demand in the United States." That is, if higher than expected load growth occurs, it will be feasible for utilities to build relatively quickly sufficient combustion turbines, combined cycle plants and similar facilities to meet the demand Id. at 19.

The probability thus is that available electrical power in the United States will suffice to meet demand until at least 1998.[9] Moreover, predicted shortfalls, if they occur at all,

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8/ "Projected available resources" reflects NERC's adjustment of total existing and planned generating capacity to reflect anticipated unavailability of some generating units during peak periods due to forced outages, seasonal deratings, maintenance requirements, and spinning reserves. Id. at 18.

In fact, total planned capacity resources, as reported by by the Regional Reliability Councils in 10-year plans submitted to DOE (IE-411 reports), will exceed demand in every region in the United States throughout the coming decade. While these national capacity margins are projected to decline over the period, the councils still predict, in aggregate, a capacity margin of not less than 17.6% in 1998. Id. at 50; see also NERC 1989 Electricity Supply & Demand For 1989-1998 (October 1989) at 24, Table 8.

9/ According to the 10-year plans submitted to DOE by the Regional Reliability Councils, capacity margins will be positive in every region throughout the entire forecasting period, with regional capacity margins ranging from 28.5% (NPCC) to 14.7% (MAIN) in 1998. Id. at 50.

will appear only in a few regions. NERC has identified only two regions in which it believes capacity additions beyond those now planned (as distinct from additional transmission capacity or load management) will be essential to maintain reliability. These are the Mid-Atlantic Area Council (MAAC) and the Northeast Power Coordinating Council (NPCC). Id. at 4-5. The latter case well illustrates the difficulties that an unfavorable regulatory environment can create for regional planners. As NERC observes:

> Unavailability of the Seabrook (1,150 MW) and Shoreham (809 MW) generating units where capacity shortages may occur in the early 1990s is of great concern.

Id. at 5. These two plants, if operational, would increase the current total installed generating capacity in the NPCC by almost 4.0%.[10] Given the high availability factor of nuclear generating plants, this increased capacity could be expected to increase the region's supply significantly, even under NERC's conservative approach to calculating "planned available resources."

Clearly, potential shortfall of capacity in one or two regions can be most immediately and directly addressed by measures tailored to the circumstances that are impeding utility investment in those regions. For example, the most direct way to increase generating capacity in the Northeast is to make sure that Seabrook and Shoreham come on line as soon as possible, rather than by an across-the board partial repeal of PUHCA. To seek wholesale changes in the structure of the electric power industry is not sound policy where more targeted solutions exist.[11]

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[10] Installed generating capacity in NPCC in 1988 was 53,913 MW. NERC, 1989 Electricity Supply & Demand at 28, Table 11.

B. Role of State Commissions: ERC agrees that, in some jurisdictions, the policies of state regulatory commissions have created major disincentives for utilities to construct new baseload plants. EIA has aptly summarized the situation as follows:

> [S]ome utilities have not been able to recover the costs of constructing new generating units that have been completed or are in various stages of completion (or even abandoned for economic reasons). Uncompleted nuclear generating plants are the most notable example. State public utility commissions may not allow all these costs to be recovered through increases in the current rate base. Those utilities with currently unrecoverable costs related to plant construction provide clear evidence of the dangers of relying on overly optimistic expectations of electricity growth in planning large investments in an uncertain regulatory environment.

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[11] The same observation applies to regions faced with losses of generating capacity now on line due to regulatory constraints. For example, according to NERC:

> "Acid rain legislation, when fully implemented, could cause the utilities in this Region [East Central Area Reliability Coordination Agreement] to lose over 9,000 megawatts of [existing] generating capacity. This capacity would have to be replaced to maintain reliability."

1989 Reliability Assessment at 4. Again, it would seem far more prudent from an electricity supply standpoint to prevent the loss of such a huge increment of capacity, rather than allowing the capacity to be lost and then citing the resulting shortfall as evidence that EWGs are needed to meet the region's needs.

Annual Energy outlook 1989, at 24 (emphasis added).

The United States Energy Association confirms that unsound regulatory policies have impeded utility construction in some jurisdictions as exemplified by the situation in the Northeast:

> As illustrated by the Shoreham and Seabrook nuclear plants, some power plants face regulatory uncertainties which could interfere with plans to meet the demand for electricity. Some jurisdictions have made it difficult for electric utilities to not only begin full operation but also to fully recover the costs associated with power plant construction. Many have disallowed recovery of sizeable investments in plants that were expected to be essential and then subsequently cancelled when their need became questionable. This has been one factor in the near halt in orders for new large baseload generating units since it has become increasingly clear that investments in such facilities are at significant risk.

USEA, 3rd Annual Assessment at 7.

However, it would not be accurate to say that state public utility commissions are primarily to blame for creating these uncertainties. In the case of Shoreham, Seabrook, and other nuclear facilities, much -- if not most -- uncertainty has arisen from federal, not state, regulatory policies. The vagaries of the nuclear licensing process at the federal level have delayed and vastly increased the costs of nuclear facilities, leading to more frequent disallowances of those costs by state regulators. Likewise, for several years utilities considering building new coal fired baseload plants have faced uncertainties about what emissions controls will be required under a yet-to-be reauthorized Clean Air Act. Current proposals for unprecedented new limitations on emissions of "greenhouse gases" from fossil fuel-fired electric powerplants have compounded this uncertainty. (Indeed, the pendency of PA 267 itself has contributed to the current climate of uncertainty for utilities as they plan for increased electricity supplies.) Thus, an ample share of responsibility for whatever potential may exist for regional electricity shortfalls rests squarely on the federal government.

Moreover, it is inaccurate to generalize about state commissions and the effects of their policies. It has been the experience of most ERC member utilities that their respective state commissions generally have adopted and followed reasonable regulatory policies over the past several years, under which the utilities have been provided appropriate incentives for investment in new capacity. While some ERC members have suffered from disallowances or refusals to allow new facilities to be placed into the rate base, ERC members believe that, in their states at least, the regulatory compact between franchised electric utilities and the public utility commission remains relatively intact.

8. What are your views on allowing utility-owned EWGs to sell power to their utility parent?

Response: It is our view that if PA 267 were adopted, utility-owned EWGs should be allowed to sell power to parent utilities. One issue regarding utility EWGs is that of abusive self-dealing. Current regulation is wholly adequate to prevent such practices and, indeed, one of NARUC's concerns is that those regulatory powers may be compromised by passage of PA 267. In practice, moreover, there would be little potential for self-dealing because independent EWGs would retain a competitive advantage that would enable them to underprice utility EWGs.

The independent EWG, as a separate corporate entity, will enjoy a real cost-of-capital advantage because it can impose additional capital costs on an unrelated corporate entity -- the purchasing utility. The associated costs are external to the EWG. As such, the independent EWG could, by virtue of its cost-of-capital advantage, price power cheaper and/or obtain higher yields for equity holders.

The utility-owned EWG, however, can only produce a cost-of-capital advantage by imposing an offsetting cost-of-capital detriment on the parent. Since the EWG and utility are contained in one corporate entity, the associated costs are internal to the corporation, and there is no net cost-of-capital advantage. The EWG/utility combination has no external organization to which it can transfer capital costs.

Thus, even if utility-owned EWGs were allowed to sell power to their utility parents, PA 267 would result in two types of corporate entities playing by two sets of rules. Independent EWGs would enjoy lower cost-of-capital based solely on their use of leveraged financing. Traditional IOUs and IOU-owned EWGs would be constrained to the traditional, much higher cost-of-capital. Such a situation is antithetical to the concept of true competition in a competitive market.

9. What are your expectations about how FERC will regulate EWGs? Do you expect that FERC will engage in traditional cost of service regulation, or will it instead allow EWGs to charge "market prices," as has been the direction FERC has recently been heading through a number of case-specific decisions?

Response: ERC cannot predict what policies FERC will follow toward EWGs under its new Chairman. The uncertainty is increased by the current vacancy on the Commission. However, ERC is unaware of any shift away from FERC's position favoring market-based pricing for EWG power, as manifested in the Commission's 1988 NOPRs.

It is certainly conceivable that the Commission will ultimately adopt some version of the NOPRs, thereby substantially exempting IPPs (EWGs) from most otherwise applicable provisions of the Federal Power Act. Under the NOPRs, EWGs' rates for wholesale power sales would be market based, with any rate established under prescribed competitive bidding procedures deemed to be "just and reasonable."[12/] Alternatively, FERC might try to accomplish substantially the same objective, i.e., market pricing of EWG power, through more cumbersome case-by-case approvals of individual EWGs' wholesale rates.[13/] In any event,

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[12/] Such market based prices for wholesale power would, however, be contrary to numerous court decisions construing the "just and reasonable" standard to require FERC to consider the cost of service before approving a wholesale rate.

[13/] See, e.g., Baltimore Gas & Electric Co., 49 FERC ¶61,170 (1987); Orange & Rockland Utilities, Inc., 42 FERC ¶61012 (1988).

absent evidence of a change in the Commission's views on the supposed advantages of "competition" in the power generation industry, the question appears to be not whether, but how, FERC would institute market-based pricing for wholesale power generated by the new crop of EWGs this bill would create.

10. Would EWGs be "fuel neutral"?

Response: It is our belief that EWGs would not be fuel neutral. The financing realities of IPP development compel this conclusion. There is a general concern in the industry about the recoverability of large coal-fired and nuclear capacity investment. Nonetheless, traditional IOUs, with their strong, independent equity base, are a better positioned than EWGs to make investments to build these billion-dollar baseload plants as needed.

The one significant area of risk that EWGs may retain, at least when relying on smaller-scale, lower-cost technologies, is that of cost overruns, untimely completion and similar construction risks.[14/] (Of course, the EWG will attempt to shift even these risks to the constructor via a turnkey contract.) Lenders in highly leveraged situations will be interested in minimizing construction risk. It is universally recognized that there is much less inherent construction risk in combined-cycle,

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[14/] Any EWG developer seeking to build a baseload plant would almost certainly seek contract provisions, such as cost-plus terms, that would leave the risk of cost overruns where it resides today, i.e., on the utility. In that case the utility would not derive even this limited benefit of EWG power, as advertised by its proponents.

or stand-alone gas turbine technology, than in either coal-fired or nuclear baseload technology. As such, developers of EWGs, and their lenders, will be biased towards gas-fired technology as capital minimizing strategies. This was recognized by the Office of Technology Assessment (OTA) in its May, 1989 report.

This is not to say that EWG development will be exclusively gas-fired. Relative to IOU capacity investment, however, it is anticipated that EWG investment will be skewed towards gas-fired technology. Questions about long-term natural gas availability and price, therefore, need to be factored into any consideration of EWGs.

11. One key issue in the PUHCA reform debate is whether IPPs would have an artificial advantage over utility powerplants due to the tax benefits of debt leveraging. A Committee staff analysis concludes that debt leveraging does not create an unfair advantage for IPPs. What are you views?

Response: Independent EWGs would enjoy a substantial cost-of-capital advantage over IOUs and it is our belief that the Committee staff analysis is in error.

"Cost-of-capital" is an economic term that describes the earnings a project would have to produce to recover investment, pay taxes, cover inflation, and give to the individual investor the required real after-tax rate of return necessary to justify investment. The cost-of-capital is the pre-tax rate of return a project must produce to yield the required after-tax rate of return at the individual investor level.

The analytical procedure is to start with this required real after-tax return to the investor. The higher are taxes, the higher will be the pre-tax return (cost-of-capital) needed to produce the required after-tax return (the hurdle rate). The more uncertain the operating performance of the project, the higher is the cost-of-capital. The more risky the investment, the higher is the cost-of-capital.

It is obvious that, all else held constant, debt finance is cheaper than equity finance due to the deductibility of debt interest at the corporate level. Thus, all else held constant, a project financed by relatively more debt will have a lower cost-of-capital than a project financed with relatively less debt. The key question here is what else can be held constant and are there any factors peculiar to the EWG that countervail the natural advantage of debt?

The debate focuses on risk. The Committee staff analysis is predicated on the proposition that the risk premium in EWG financing is sufficiently large to overwhelm the tax advantage of debt and, therefore, there is no inherent cost-of-capital advantage to EWGs. An analysis of the relative risks of EWG versus IOU investment will show that the Committee staff analysis is wrong.

There are three basic categories of risk that must be accounted for, and into which all significant risks associated with the utility business may be subsumed. These are (1) construction risk, (2) market risk, and (3) operations risk. These will be discussed in order.

Construction Risk

Construction risk concerns the possibility that facilities will not be built on time or on budget. Current perceptions of construction risk are based on prior experience with cost overruns and disallowances.

Proponents of EWGs argued that EWGs will shift construction risk from utilities to themselves. If this were true, the risk premium in an EWG's cost-of-capital would be higher than that for an IOU. In fact, however, construction risk should be neutral between IOUs and EWGs because EWGs could shift construction risks elsewhere. This is true for several reasons.

First, the construction risk inherent in combined-cycle technology is less than for large baseload facilities based on coal-fired or nuclear technology. Thus, for the next round of construction, construction risk is not as important a factor. As stated by Glenn McIsaac of Energy Associates, Inc., the "construction lead times, costs and operating performance of the next round of capacity additions planned by utilities will be far less risky."[15/]

Second, both IOUs and EWGs are equally capable of shifting construction risk onto vendors through use of turnkey contracts. This was confirmed, for EWGs, by Joseph Kearney, CEO of PG&E-Bechtel Generating Company, in testimony before the Committee:

[15/] McIsaac *supra*. at 12-3.

> The reality from the risk standpoint is that the risks have been moved to other players, the contract with the constructor, for example, which has been the classic, large risk on the utilities, cost overruns, plant schedules and performance. Now, that is all undertaken by the contractors, and that is significantly why we can take these higher debt ratios, and it does not reflect any higher risks to the project itself.[16]

Utilities will also be able to shift construction risks. McIsaac states that "utilities are likely to have more projects built on a turnkey basis in the future, providing further insulation from construction risk."[17]

It should be noted that the ability to shift construction risk to the contractor will be possible for gas-turbine and combined-cycled facilities. This may not be the case for large baseload facilities. For such facilities, construction risk will most probably be shifted to the utility, e.g., through cost-plus contracts. Discussions with rating agencies confirm the view that construction risks for EWGs will not be greater than for IOUs. In the opinion of rating agencies, and in their rating of companies and projects, risk is neutral between IOU and EWG development. Thus, there is no basis to believe that construction risk results in a higher risk premium in the cost-of-capital for EWGs.

16/ Transcript of Hearings Before the Committee on Energy and Natural Resources, November 16, 1989. p. 78.

17/ McIsaac *supra* at 12-3

Market Risk

Market risk relates to the fear that customers will not exist in the future for planned capacity and therefore there will not be a guaranteed revenue stream to cover debt and equity service. However, market risk is shifted from the EWG onto the purchasing utility by contract and therefore the EWG faces no market risk. The take-or-pay nature of probable contractual arrangements is the mechanism by which the EWG is assured the necessary revenue stream.

Robert Burke, Senior Vice President of Moody's Investor Services has stated:

> Many contracts are designed to place most all of the risk on the utility company. An absolute "take or pay" contract places the risk of both demand and operating performance on the purchasing utility."[18]

Glenn McIsaac confirms that take or pay contracts will be the norm:

> These commitments typically provide the independent producers with an assured market and a known price for their facilities' output. These assurances are extremely important because they assign the "market risk" to the utility rather than the IPP...
>
> Under contracts which provide an assured market and an assured price to IPPs, the purchasing utilities bear the risk that the power will not be needed in the future or will be uneconomic relative to other sources of supply. These are the most

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[18] Robert W. Burke "Independent Power Producers and Their Impact on Utility Debt Quality" Remarks before the Energy Daily's Annual Utility Conference. November 2, 1989 pp 5, 6.

> significant risks associated with investment in electric generating facilities.[19]

Professor Timothy Nantell of the University of Minnesota states that "there is a powerful incentive for the developer to select a purchaser with good credit and to negotiate a contract that maximizes the purchaser's payment obligations. The lender then looks through the developer, to the purchaser, to assure debt service."[20] Two insurance executives, Glenn Ikemoto and Susan Carlow state that "[t]his long-term contract with price certainty and guaranteed sales removes the market risk from the venture."[21]

Thus, contracts with guaranteed capacity payments shift market risk from the EWG to the IOU. Discussions with investment bankers confirm that lenders will require such contracts. In a recent article in Cogeneration, Charles R. Frank, Jr., Senior Vice President and Manager of Energy Project and Utility Financing for GE Capital Corp., a major financing entity, discussed the types of contracts GE Capital looks for when underwriting independent power projects:

> We tend to favor pricing based on a capacity component defined in terms of dollars-per-kilowatt-per-month or-year and on an energy component defined in terms of cents-per-kilowatt hour.

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[19] McIsaac supra at 12-3.

[20] Timothy Nantell and Lee R. Carlson "The Hidden Cost of Fixed Payment Contracts" unpublished. p42-2.

[21] Glenn Ikemoto and Susan Carlow, "Power Contract Security: Balancing Price and Quality" unpublished p11-2

> Pricing based on a single cents-per-kilowatt-hour component is more affected by output fluctuations and tends to be riskier to the financier...
>
> The capacity charge should cover all costs which are not variable, including fixed operating costs, fixed fuel costs (such as demand charges for pipeline access) and financing costs, including debt service and a fair return to equity.[22/]

Clearly, the types of contract required by GE Capital shift market risk onto the purchasing utility.

Proponents of PA 267 do not conceal their belief that the purchasing utility should bear the market risk. In testimony before the Committee, William Berry, CEO of Virginia Power stated:

> And finally, there is the need for power. Do you really need this project? That risk is now borne by utilities and their customers and it would continue to be borne by utilities and their customers.[23/]

Mr. Berry continues:

> The utility retains some risk as I have indicated before, market risks, fuel price risks, and that we have a contract with the independent generator that shelters him from that risk and therefore he can take on that debt without adding to his business risk.[24/]

[22/] Charles R. Frank, Jr. "Financiers of Alternative Energy Now Willing to Assume More Project Risk" Congeneration September-October 1989 p 34.

[23/] Transcript supra at 74.

[24/] Id. at 76.

Later, Mr. Berry confirms his position on contracts and market risk:

> The contract that the independent producer has with the utility is an assurance of payment regardless of market demand and regardless of fuel prices because these two items in my judgment continue to be utility and utility customer risks.[25]

Thus, in the view of financiers, insurance executives, rating agencies, and industry executive proponents of IPP power, market risk would be and should be shifted from EWGs to utilities. In the words of Joseph Kearney, CEO of PG&E-Bechtel Generating Company, "If there was any higher risk, we would not be able to finance the 80, 90 percent level which is generally where these are financed at."[26] There is, therefore, no risk premium associated with market risk in an EWG's cost-of-capital.

Operations Risk

The two most important components of operations risk are performance risk and fuel cost risk. Both of these risks will be primarily, though not totally, shifted from EWGs to purchasing utilities.

Performance risk relates to the fear that new capacity will not perform up to standards. (It should be noted that one large rating agency assumes that IPP power is inherently less reliable than IOU power because the IPP has no statutory obligation to serve.) The question is, if IPP power is more risky from a performance standpoint, who bears that risk? The answer is that the utility, not the IPP, bears the risk. According to Robert Burke of Moody's Investor Services:

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[25] *Id.* at 77

[26] *Id.* *supra* at 79.

> If an "independent" turns out to be unreliable, the electric utility will be the one to be blamed by both customers and regulators. The utilities will have given up control over their generating sources and yet will continue to shoulder the responsibility for problems or changes in economic or legislative conditions. A lose-lose situation could develop from the utility point of view.27/

Standard & Poor's Corporation has stated:

> Unless state regulators are willing to accept bidding competition as a substitute for a utility's obligation to serve (a very unlikely eventuality) construction or operating shortcomings by a third party generator could result in regulatorily imposed penalties against the purchasing utility. Similarly, if contracted purchased power fails to materialize or proves to be unreliable the utility may be required to accelerate its own construction activities at a late date, thereby resulting in greater cost than previously anticipated and a greater risk of regulatory disallowance. The utility has an obligation to serve; the third party producers do not.28/

William Berry has indicated his belief that utilities will bear performance risk when contracting with EWGs:

> And on the other side you would have to say the utilities are taking on the risk as to whether these people actually perform

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27/ Burke supra at 8.

28/ Thomas D. Mockler, Standard & Poors Corporation. Letter provided to Senator McClure, February 4, 1988. p3.

> under contracts. So, we have a shifting of risks.[29]

It is clear that the overwhelming majority of performance risk is shifted to the utility because, due to the statutory obligation to serve, the purchasing utility is the ultimate guarantor of EWG performance.

Fuel cost risk reflects the fear that fuels used in electric generation will become more expensive in the future. According to Charles Frank, GE Capital Corp. is very sensitive to fuel cost risks:

> Fossil-fuel price risks are far more serious than inflation risks, in our opinion. A project can be adversely affected by both rising and falling fuel prices, depending on whether costs or revenues are more sensitive to change.[30]

Frank's article lists some hedging techniques but concludes:

> None of these hedge techniques is as desirable as a well-crafted power sales agreement. GE Capital resorts to hedging on occasion but finds it much easier to finance projects relatively insensitive to energy prices."[31]

The fuel cost risk, he notes, is shifted in the energy component of the power contract which "should cover the variable costs of running the plant."[32]

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[29] Transcript supra at 75.

[30] Frank supra at 35.

[31] Id.

[32] Id.

Discussions with investment bankers confirm that lenders will require some form of fuel cost escalator clause in the purchase power contract. To date these contracts have shifted most, but not all, of the fuel cost risk to purchasing utilities. Contracts have been based on general production cost indexes, or general fuel price indexes, rather than specifically linked to the price of, say, natural gas.

Fuel cost risks are mainly shifted to the purchasing utility and that is how it should be, according to proponents of PA 267. As stated by William Berry:

> Fuel price risk, the general cost of fuel, not a specific contract, but is oil going to triple or something like that, is now borne by utilities and their customers. And we think that under a good contract they should continue to be borne by utilities and their customers.[33]

In short, operations risks, including both performance risks and fuel cost risks, are shifted from the EWG to the purchasing utility. Thus, there is no reason to believe that there will be a higher risk premium associated with operations risk in an EWG's cost-of-capital.

Summary and the Committee Staff's Analysis

The three areas of primary risk associated with electric power generation are construction, market and operating risk. The same quantum of construction risk exists, regardless of whether the developer is an IOU or an EWG. Rating agency

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33/ Transcript *supra* at 74.

executives, insurance executives, financial executives and industry executives who support IPP development agree that market and operations risk will be borne, not by the EWG, but by the purchasing utility. Thus, there is no real risk on the EWG that could give rise to a significant risk premimum.[34]

How, then, does the Committee staff report conclude that there is no inherent cost-of-capital advantage for EWGs? The Committee staff assumes that there is an enormous risk premium in required equity rates of return, even though there is only a very small risk premium in debt interest rates. Although the debt risk premium is 50 to 100 basis points (this level has been confirmed by rating agency executives and financiers) under all financing scenarios postulated by the Staff Study, The assumed risk premium in equity rates ranges from 200 to 750 basis points. Only under the most extreme scenario, i.e. the 700-750 basis point risk premium, would the EWG have a cost-of-capital as high as or higher than the utility.

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[34] In evaluating IPP projects, financiers assign an element of risk reflecting the fact that no contract, even the take-or-pay contract that will guarantee project revenues, is absolutely iron-clad. Thus, there will be a small risk associated the EWG that would not exist were the utility developing the project itself. Recognizing the improbability of contract abrogation by a utility, however, the market would require the EWG to pay a risk premium of no more than 50-100 basis points. This relatively small risk premium for EWGs has been confirmed by rating agency and investment banking executves, and is consistent with the Staff study's assumptions. Within the context of a cost of capital calculation, the tax advantage of debt dwarfs this minor differential in interest rates for EWGs versus IOUs.

We question the assumption of such enormous risk premiums in equity rates for prospective EWGs. If debt holders were well aware of the shifting of risk from the EWG, why wouldn't the equity holders be equally aware of the take-or-pay contract, the assured revenue stream, the fuel cost escalator costs, etc.?

In fact, equity holders would be aware of the risk situation. The Committee staff result is based on observations of historic proffered "hurdle" equity rates for certain QF projects, which are unlikely to be valid for prospective EWGs.

Equity rates of return on PURPA QF projects that are desired by investment bankers at an early stage of IPP development are no gauge of the risk premiums in required equity hurdle rates that would pertain for EWGs in a competitive capital market. In fact, discussions with rating agency executives confirm that the QF hurdle rates are falling rapidly, due to arbitrage, as more financiers enter the market and become familiar with the projects.[35]

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[35] Hurdle rates are the returns that investment bankers hope to realize, based on their economic analysis of a project's potential prior to underwriting it. This is in distinction to market-determined required rates at economic equilibrium.

One must be very careful about statements concerning equity rates of return. The actual equity return, as opposed to some proffered hurdle rate, is a residual. It is what is left after all costs have been paid, including wages, raw materials, services and debt service. The actual equity return can be zero or even negative. This is distinct from a debt return which is, absent default, the same as its hurdle rate.

The market equity return must be distinguished from that which is stated in a brochure whose purpose is to attract investors to an EWG project. In fact, the prospectus could hold out the possibility of such attractive, extra normal returns to equity only because the project is so heavily

Continued

It is clear that as the market matures, equity rates for EWGs would accurately reflect risks in the same manner as interest rates. It is to be expected that risk premiums in required equity returns would be similar to those in EWG interest rates. Such risk premiums would reflect the market's recognition that virtually all risk was shifted onto the purchasing utility. Any other conclusion regarding required equity returns for EWGs can only be based on the proposition that either there is no competitive market for equity or there will be prolonged and profound errors of judgment on the part of equity investors.

In conclusion, the risk premiums associated with EWG financing would be small. The tax advantage to debt would far exceed any countervailing risk premium in the cost-of-capital. EWGs would enjoy an inherent and artificial cost-of-capital advantage.

B. Questions of Senator Conrad

ERC has no information responsive to these questions other than as set forth in ERC's written testimony and in the foregoing responses.

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leveraged and income is transferred from the federal government to prospective shareholders. Moreover, regardless of what a prospectus might promise, the real world market inexorably will arbitrage away extra normal equity returns for such projects until the real required equity rate is achieved.

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JOSEPH F. PAQUETTE, JR
CHAIRMAN, PRESIDENT
AND CHIEF EXECUTIVE OFFICER

Janaury 26, 1990

William B. Conway, Esquire
Senior Counsel
Water and Power Subcommittee
364 Dirkson
Committee on Energy and Natural Resources
Washington DC 20510-6150

Dear Mr. Conway:

In response to Senator Johnston's letter of December 20, 1989, attached are my replies to the questions posed by Senator McClure in connection with the Full Committee on Energy and Natural Resources on Amendment 267 to S. 406.

Respectfully,

Joseph F Paquette Jr

attachment
pal

RESPONSES OF JOSEPH F. PAQUETTE, JR. TO QUESTIONS REGARDING COMPETITIVE WHOLESALE ELECTRIC GENERATION ACT OF 1989

A. Questions of Senator McClure

1. Do you support Printed Amendment No. 267 as introduced? If not, what changes would be necessary to secure your support? Please provide the Committee with the statutory language which you would propose to be added.

Response: I do not support Printed Amendment No. 267 as introduced. I believe the extensive amendments that would be necessary to secure my support would so fundamentally change the bill as to make it unacceptable to current proponents.

2. Would you support PA 267 if the recommendations of the National Association of Regulatory Utility Commissioners are added? See attached summary of NARUC.

Response: No.

3. Would you support PA 267 of a transmission access or mandatory wheeling provision is added?

Response: Absolutely not.

4. PUCHA was enacted to address very serious problems caused by utility holding companies. Is the current absence of abuses evidence that PUCHA has outlived its usefulness, or proof that it continues to work effectively?

Response: The current absence of abuses of the type associated with utility holding companies prior to the 1930s is the product of historical evolution and reflects a combination of factors. Most of the conditions that gave rise to PUCHA no longer exist. This is not to say, however, that the Holding Company Act has outlived its usefulness.

5. What impact would PA 267 have on the structure of the electric utility industry?

Response: It is my firm belief that, should the amendment be adopted, the structure of the electric utility industry will be changed dramatically. A significant portion of electric generation would be provided by EWGs.

6. What impact would PA 267 have on the price, supply and reliability of electricity?

Response: If utilities are compelled (or elect) to purchase EWG power due to its apparently lower price, it is clear that electricity will probably be more expensive in the mid-term and over the long haul and be less reliable.

7. A key assumption of PA 267 is that not enough powerplants are now being constructed to meet future power needs. Is that true everywhere, or only in certain states or regions? Do you agree with the assertion made by some that state public utility commissions are primarily to blame for the lack of adequate powerplant construction, or are other factors responsible?

Response:

A. Adequacy of Supply: I do not believe the available evidence warrants the conclusion that too few powerplants are now being constructed to meet future needs. The key factor in planning for needed generating capacity additions is anticipated demand for electric power. There is, however, substantial disagreement about the rate at which electricity demand will grow in the United States over the next decade, and thus about whether planned capacity additions will be sufficient to meet demand throughout that 10-year period.

8. What are your views on allowing utility-owned EWGs to sell power to their utility parent?

Response: It is my view that if PA 267 were adopted, utility-owned EWGs should not be allowed to sell power to parent utilities.

9. What are your expectations about how FERC will regulate EWGs? Do you expect that FERC will engage in traditional cost of service regulation, or will it instead allow EWGs to charge "market prices," as has been the direction FERC has recently been heading through a number of case-specific decisions?

Response: I cannot predict what policies FERC will follow toward EWGs under its new Chairman. The uncertainty is increased by the current vacancy on the Commission. In addition, FERC may be reluctant to venture into the inextricably related issue of transmission access for IPP/EWGs.

10. Would EWGs be "fuel neutral"?

Response: It is my belief that EWGs would not be fuel neutral. The financing realities of IPP development compel this conclusion. There is a general concern in the industry about the recoverability of large coal-fired and nuclear capacity investment. Nonetheless, traditional IOUs, with their strong, independent equity base, are a better positioned than EWGs to make investments to build these billion-dollar baseload plants as needed.

The one significant area of risk that EWGs may retain, not fully shift to purchasing utilities, is that of cost overruns, untimely competition and similar construction risks (the EWG will attempt to shift these to the constructor). Lenders in highly leveraged situations will be interested in minimizing construction risk. It is universally recognized that there is much less inherent construction risk in combined-cycle, or stand-alone gas turbine technology, than in either coal-fired or nuclear baseload technology. As such, developers of EWGs, and their lenders, will be biased towards gas-fired technology as capital minimizing strategies. This was recognized by the Office of Technology Assessment (OTA) in its May, 1989 report.

This is not to say that EWG development will be exclusively gas-fired. Relative to IOU capacity investment, however, it is anticipated that EWG investment will be skewed towards gas-fired technology.

11. One key issue in the PUCHA reform debate is whether IPPs would have an artificial advantage over utility powerplants due to the tax benefits of debt leveraging. A Committee staff analysis concludes that debt leveraging does not create an unfair advantage for IPPs. What are your views?

Response: It is my belief that independent EWGs would enjoy a substantial cost-of-capital advantage over IOUs because of more debt leveraging and that the Committee staff analysis is in error.

WILLIAM McCOLLAM Jr President

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February 5, 1990

The Honorable J. Bennett Johnston
Chairman
Committee on Energy and Natural Resources
United States Senate
Washington, D.C. 20510

Dear Mr. Chairman:

Enclosed are answers to the questions posed by your letter dated December 20, 1989. We appreciate the opportunity to expound on the issues raised during your Committee's hearings on November 16, 1989.

If we can be of any further assistance, please let me know.

Sincerely yours,

William McCollam, Jr.

William McCollam, Jr.

WM:dos
Enclosures

ANSWERS TO QUESTIONS
FROM
SENATOR JAMES A. MCCLURE

1. Do you support Printed Amendment No. 267 as introduced? If not, what changes would be necessary to secure your support? Please provide the Committee with the statutory language which you would propose be added.

Response: The issues presented by PUHCA are complex and have produced divergent viewpoints within the electric utility industry as to what changes would result from the proposed legislation and whether the potential benefits of increased competition would outweigh the potential costs. Thus, EEI is unable to take a position on the proposed legislation.

But even with those differences, there are areas of strong agreement among EEI member companies relative to many of the issues which have been raised in the debate as to whether changes in PUHCA would be beneficial to the long-term interests of electric consumers. Our industry is in complete agreement that the following elements are critical to assuring that electric consumers are provided with adequate, reliable, and environmentally acceptable service at the lowest reasonable cost:

(1) PUHCA changes should not in practice preclude a utility or its affiliates from participating in wholesale markets on an equal basis with other entities.

(2) An electric utility should retain its managerial discretion to decide whether it will build facilities for itself or purchase electricity from others.

(3) The provision of transmission services should remain voluntary recognizing that such services can be facilitated through appropriate pricing.

These elements recognize that electric generation, transmission and distribution all have to work together as a single, perfectly coordinated system in order to keep the lights on. And to achieve that coordination, a single entity must have responsibility for the integrated planning and operation of generation, transmission, and distribution. Regulated utilities, with their obligation to serve customers, are the ultimate parties who must answer to state regulators for the quality of electric service so it is operationally essential and also fair that utilities retain control over the system.

2. Would you support PA 267 if the recommendations of the National Association of Regulatory Commissioners are added?

Response: EEI does not support the National Association of Regulatory Commissioners (NARUC) recommendations. The NARUC recommendations raise a new set of complex and controversial issues concerning the delicate balance of jurisdiction between federal and state regulatory authorities. These issues involve legal precedents and decisions under the Federal Power Act, the Public Utility Holding Company Act, state laws, and regulations. They affect utility planning and operating decisions for providing adequate, reliable, and environmentally acceptable service to customers at the lowest reasonable cost.

We also believe that adequate authorities already exist, and would continue to exist if PA 267 were enacted, at both FERC and state public utility commission levels to ensure that practices of utilities and their affiliates continue to be fair for electric consumers.

3. Would your support PA 267 if a transmission access or a mandatory wheeling provision is added?

Response: EEI strongly opposes the addition of any transmission access or mandatory wheeling legislation. Mandatory wheeling creates serious reliability, economic and equity concerns for owners of transmission systems and their customers. There is no evidence to suggest that mandatory wheeling is either necessary or desirable to ensure adequate future power supplies. Non-utility development of generation, through PURPA and competitive bidding experiments at the state level, has occurred quite successfully under the current legislative/regulatory framework for transmission. In our comments to FERC on the Competitive Bidding Notice of Proposed Rulemaking (Appendix A), we provide a complete description of why mandatory transmission for non-utility generation is not in the national interest. Those comments are appended here for your reference.

4. PUHCA was enacted to address very serious problems caused by utility holding companies. Is the current absence of abuses evidence that PUHCA has outlived its usefulness, or proof that it continues to work effectively?

Response: While some aspects of PUHCA regulation have been superseded by the significant development of state regulation since passage of the Act in 1935, PA 267 is a limited amendment designed to address the issue as to whether purely wholesale generation enterprises should be subject to the Act. The question then becomes whether state regulation (and FERC regulation under the Federal Power Act) is sufficient to prevent any abuses which might occur by exempting such generating enterprises from the Act. We believe the answer is yes.

5. What impact would PA 267 have on the structure of the electric utility industry?

Response: It depends upon whether PA267 would produce fair competition. For example, it would not be fair competition if utilities were not able to purchase from others, including affiliates, based on price and non-price factors, under competitive bidding or another procurement plan. It would also be unfair if non-utility generators were able to use leveraged financing or were exempted from other regulatory burdens, and utilities were not permitted to form affiliates which enjoy the same advantages.

Some industry analysts predict that eventually generation would likely become more and more separate from the transmission and distribution functions of the current vertically integrated industry, as competition for new generation increased. This would cause increased reliance on long-term contracts as a means of providing future power supplies. These risks relate to utilities' management discretion over short- and long-term planning and operating decisions in the best interests of electric customers, whom they have an obligation to serve. An absolute take-or-pay contract places the risk of both demand and operating performance of the non-utility supplier on the purchasing utility.

The recent report of the Office of Technology Assessment (Electric Power Wheeling and Dealing: Technological Considerations for Increasing Competition) pointed out, there is a substantial lack of information and considerable uncertainty regarding the potential costs and benefits of increasing competition in the generation sector. Thus, while PA 267, to the extent it increases competition for new generation, is likely to affect industry structure in the long-term, the effect of such change is not currently ascertainable.

6. **What impact would PA 267 have on the price, supply and reliability of electricity?**

Response: The electric utility industry is committed to providing adequate and reliable supplies of electricity in the future at the lowest reasonable cost. To meet this goal, we believe that utility management must have maximum flexibility to choose among power supply options which best meet the needs of its customers. Some of our member companies believe that PA 267 would ultimately reduce this necessary management flexibility and discretion, while others believe that PA 267 is necessary to provide such flexibility. However, it is important to keep in mind that all utilities share these common objectives. The debate over the proper statutory and regulatory framework to meet these objectives is one which the Congress must carefully consider.

With respect to reliability of future power supply, EEI's concerns relate both to the overreliance on contracts to fulfill utility service obligations, and the problems of integrating large numbers of non-utility generators into the utility power supply system. Again, these issues were discussed fully in an Appendix (Appendix B) to EEI's comments on FERC's Competitive Bidding NOPR, which is attached for your reference.

7. A key assumption of PA 267 is that not enough powerplants are now being constructed to meet future power needs. Is that true everywhere, or only in certain states or regions? Do you agree with the assertion made by some that state public utility commissions are primarily to blame for the lack of adequate powerplant construction, or are other factors responsible?

Response: We do not agree with the assumption that not enough powerplants are now being constructed to meet future power needs. All utilities have plans in place to meet their future generating needs. These include a broad array of supply options (improving the operation of existing power plants, refurbishing older plants, planning capacity additions, exchanging power with other utilities, purchasing power from third parties and selecting from a variety of fuel sources) and demand side management programs.

What is true is that utility resource plans have become riskier over the past several years. The reasons behind this increased risk are complex and dependent on many factors. The reluctance of some state public utility commissions to allow utilities to recover prudently incurred costs is just one of those factors. Additional factors are uncertain federal policies and public perceptions which make it extremely difficult for utilities to obtain an optimal mix of resources, including large baseload coal and nuclear units which offer the benefits of economies of scale and long-run allocative efficiencies.

8. What are your views on allowing utility-owned EWGs to sell power to their utility parent?

Response: It would be critical that utility-owned EWGs be allowed to sell power to their utility parent. A system which precludes existing utilities from participating with non-utilities would be both unfair and harmful to electric consumers. It would also not be a competitive system. To restrict the utility-affiliate option would preclude the most experienced and knowledgeable player in generation from competing, resulting in higher than necessary costs to customers. Any potential for unfair self-dealing could and would be dealt with through existing regulatory mechanisms.

9. **What are your expectations about how FERC will regulate EWGs? Do you expect that FERC will engage in traditional cost of service regulation, or will it instead allow EWGs to charge "market prices," as has been the direction FERC has recently been heading through a number of case-specific decisions?**

Response: Given the substantial turnover in FERC personnel over the past year, EEI cannot speculate as to what direction FERC is likely to take. To the extent that EWGs become a reality, our hope is that FERC will consider EWG regulation on a case-by-case basis. Moreover, regulatory pricing policy should also be considered on the basis of individual factual circumstances, rather than on the basis of any generic "bright-line" tests as to when "market prices" are or are not appropriate.

10. Would EWGs be "fuel neutral?"

Response: Some have suggested that EWGs would be likely to rely on natural gas, because of the relatively low capital costs of gas-fired generation and short-term gas availability. Non-utility sources accounted for approximately 5 percent of total U.S. generating capacity at year end 1989, and 37 percent of non-utility capacity was fueled by natural gas. So there are legitimate concerns about an overreliance on natural gas, particularly if there is a greater dependency on non-utility sources in the future. It is important that utilities be allowed to maintain the discretion to determine the most appropriate fuel supply mix which is in the best long-term interests of their customers, to purchase power when that is consistent with fuel mix and other power supply requirements, and to construct their own generation when that is the best option.

11. One key issue in the PUHCA reform debate is whether IPPs would have an artificial advantage over utility powerplants due to the tax benefits of debt leveraging. A Committee staff analysis concludes that debt leveraging does not create an unfair advantage for IPPs. What are your views?

Response: A critical issue is whether the long-term contract with the IPP imposes any risks on the purchasing utility. With take-or-pay contracts, IPPs are perceived as having less business risk than regulated utilities by virtue of the strength of such contracts. Conversations with investment and commercial bankers who do project financing confirm that they place considerable weight on the quality of the take-or-pay contract in their evaluation of the business risk of an IPP project. It therefore follows that the cost of debt to the IPP will not necessarily reflect either the inherent credit quality of the owner or the IPP debt leverage, but, instead, the strength of the revenue stream based on the take-or-pay contract with the purchasing electric utility. Further, if the quality of the utility's promise to pay is sufficiently high, the entire capital investment in the associated IPP would tend to be regarded as the equivalent of direct issuance of debt by the utility, almost regardless of the debt leverage of the IPP, thus increasing the cost of capital to the purchasing utility.

The attached presentation by Robert W. Burke of Moody's Investor Service corroborates many of these points.

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ANSWERS TO QUESTIONS
FROM
SENATOR KENT CONRAD

Many of the questions posed by Senator Conrad concern evolving issues where there is limited information. In an effort to be as responsive as possible to the questions, EEI has conducted a literature review, undertaken discussions with experts in the financial community, and relied upon its knowledge of the operations of capital markets. Our responses assume that cogenerators are included within the term IPP.

1. The anticipated debt-equity ratios of IPP projects?

Response: Structuring the capitalization of a business entity depends on considerations such as the economics of the project (cash flows and earnings), the economics of the capitalization (the weighted costs of each type of capital) and the amount of risk and risk allocation between buyer, sellers and types of investors. An example of risk allocation is the take-or-pay or take-and-pay contract. We would point out that debt is used in financing not only for its tax advantages, but because it is considered less risky than equity thus resulting in a lower cost. In most businesses debt is protected by an equity cushion. Generally our reading of the literature and discussions with project financiers is that debt equity ratios range from 80-100% However, such high debt leverage is usually allowed only where the project provides considerable assurance of a reliable income stream, as through a take-or-pay or similar contract, which essentially transfers substantial risks to the purchaser of the project's output.

2. Whether such facilities would typically be "project-financed" (i.e., through issuance of debt without recourse to parent companies or other third parties)?

Response: Based on our discussion with experts and a scanning of the study on independent renewable electricity developers done by the Investor Responsibility Research Center, entitled "Power Plays"*, financing is typically project-specific. This study also indicates, when the data is available, that almost all of the financing involves limited recourse or no recourse to parent companies or other third parties.

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* Susan Williams and Kevin Porter - "Power Plays - Profits of America's Independent Renewable Electricity Developers", 1989 Edition, Investor Responsibility Research Center, Washington, D.C.

3. The term of debt financing for such projects?

Response: Often the term of financing is considerably shorter than the economic life of the project.* We understand that debt for such projects typically has a 12-15 year term, with some terms as long as 20 years.

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* E.P. Kahn, C.A. Goldman, S. Stoft and D. Berman; Evaluation Methods in Competitive Bidding for Electric Power; Lawrence Berkely Laboratory, Berkely, California; June 1989; p. 2-8.

4. **Whether such projects can be financed on economic terms without guaranteed purchase or take-or-pay requirements or similar provisions in their power sales contracts which will assure a stable cash flow?**

Response: We believe that a large preponderance of IPP projects are based on take-or-pay, or take-and-pay contracts and that lenders generally would not finance a project that did not have this type of contract clause. Lenders understand this form of financing and have found that a take-or-pay, or take-and-pay, contract is an essential element of strong credit. A strong credit results in lower financing costs. Daniel A. Potash, Vice President, Cogeneration Capital Associates, Inc., sums up the way that bankers treat risk:

> Each contract has to stand up to the scrutiny of conservative bankers, whose job is to estimate the credit risks in a large and complex cogeneration project financing. Many projects have failed to get financing because one relatively small piece of the financial development puzzle--a permit, an easement, a security lien--was improperly structured or missing.*

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* Daniel A. Potash; 10 Financial Pitfalls to Avoid In Developing a Generation Project; World Cogeneration; Summer 1989; p. 13.

5. Whether such projects can be financed on economic terms without fuel-cost adjustment or escalator or similar provisions in their power sales contracts which will insulate them from the risk of fuel cost increases?

Response: For many of the reasons stated in the answer to Question 4, we believe the answer to be the same. To quote Daniel Potash again:

> Electric Revenue/Fuel Expense Relationship. Along the same lines as number four, bankers want to see fuel expense and electricity revenue move in tandem. If the changes in fuel cost are not tied to changes in electrical revenue, through contract or regulation, financing will be a rocky road.

Reid & Priest has found that "Fuel costs and O&M expenses often are indexed."* As a note, the index does not necessarily have to be an index of the fuel used by the generator. To the extent the index tracks the cost of the project's fuel explicitly, all fuel price risks are transferred to the purchaser. Use of other types of indexes may result in different allocations of fuel price risks.

* Reid & Priest; Electric Power Purchasing Handbook; Executive Enterprises Publications Co., Inc.; N.Y.C.

6. What percentage of current qualifying facilities have debt-equity rations exceeding 80-20?

Response: Since this information is not readily available, we contacted various commercial and investment bankers who have experience in financing projects for qualifying facilities. Based on those conversations we would estimate the ratio currently to be about 85 percent debt and 15 percent equity. Some projects are financed with no equity at all. Others are financed using general corporate funds.

7. What percentage of QFs are "project-financed"?

Response: We have received an estimate of about 90 percent project financing.

8. The magnitude of the risk premiums (i.e., higher debt and/or equity costs as compared with utilities), if any, that have been required to be paid in order to obtain debt and/or equity financing for existing QFs?

Response: With respect to equity, a recent article in Business Week states that, "Independents shoot for a 25 percent return on equity..."* During the second quarter of 1989, electric utilities requested an ROE of 13.6 percent and state and local authorities granted a ROE of 13.0 percent. One estimate of the debt risk premium is 100 basis points.

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* New Boys Shake Up the Power Grid; Business Week; January 9, 1990; p. 2.

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APPENDIX A

MANDATORY TRANSMISSION SERVICES AS A CONDITION OF COMPETITIVE BIDDING WOULD PROMOTE INEFFICIENCY, IS UNNECESSARY, AND IS BEYOND FERC'S AUTHORITY

APPENDIX A

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I. INTRODUCTION

In the Preamble to the Notice of Proposed Rulemaking on Regulations Governing Competitive Bidding, the Commission presents a discussion and seeks comment on the role of transmission pricing and access in the proposed competitive bidding scheme.[1] Specifically, the NOPR discusses a proposal to condition competitive bidding programs on mandatory "wheeling in" or "wheeling out" on the part of utilities participating in competitive procurement.

"Wheeling in," as described in the NOPR, would require that a utility which wishes to submit a bid to satisfy the capacity needs of another utility provide firm transmission service for successful bidders within its service territory or capable of reaching one of its interconnection points.[2] "Wheeling out" is described in the NOPR as requiring utilities submitting bids to satisfy their own capacity needs to provide transmission service to losing bidders that wish to sell to another wholesale power purchaser.[3]

The purpose of this Appendix is to respond to both the questions and issues raised by the NOPR as well as additional issues which have been raised by numerous parties who have advocated the conditioning of competitive bidding on mandatory access to transmission.[4]

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[1] NOPR at 87.

[2] NOPR at 87.

[3] NOPR at 89.

The current Commission initiatives as described in the instant NOPR, as we understand them, are for the asserted purposes of encouraging efficiency in power supply and allowing PURPA's avoided cost standard to be determined more accurately through increased supplier competition. As discussed in the Introduction (Section I) of the main body of our comments, EEI believes, inter alia, that if these initiatives go forward;

(1) The implementation of bidding for purchases from non-QF sources must be voluntary to the utility;

(2) The utility must have the option of participating in bidding on the same basis as other participants, inside or outside of its service territory, or building under traditional cost of service regulation;

(3) The utility maintains control over non-price factors in the bidding process;

(4) Competitive bidding is not conditioned on the mandatory provision of transmission services;

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[4] See, for example, "Analysis of the Federal Energy Regulatory Commission's Authority and Obligation to Condition Approval of Competitive Bid Systems on Electric Utilities Agreement to Provide Nondiscriminatory Transmission Access for Non-Utility Power." Sutherland, Asbill and Brennan (December 1, 1987) (hereafter "SAB Memo"); ELCON Memo to FERC staff; Efforts to Encourage Competition Without Transmission Access Are Fatally Flawed." Crowell and Moring for the Electricity Consumers Resource Council (September 23, 1987) (hereafter "ELCON Memo"); and "'Wheeling Out' and 'Wheeling In' as a Conditional Element of FERC's All-Source Competitive Bidding Proposal." Cleary, Gottleib, Steen and Hamilton for the Competitive Electric Power Alliance (CEPA) and ELCON (March 8, 1988) (hereafter "ELCON/CEPA Memo").

(5) **Utility solicitations and payments for capacity, whether from QFs or non-QFs, are only offered when capacity is needed, and;**

(6) **All participants in bidding must compete on equal terms, and where necessary to achieve this result, federal statutes and regulations should be changed.**

The many parties who have argued for the conditioning of competitive bidding on the provision of transmission services have based their primary arguments on the basis of two suppositions. First, that without mandatory wheeling, discrimination will result in violation of PURPA and or the Federal Power Act. Second, that mandatory wheeling is necessary to achieve competition in the generation sector. The NOPR itself contradicts these two suppositions.

With respect to the discrimination issue, as long as QFs have an opportunity to supply their power to the local utility at its avoided costs, there is no discrimination. As the NOPR points out: "[u]nder properly structured bidding procedures, QFs would not be discriminated against."[5] This issue is discussed in greater detail in Sections III and IV of this Appendix.

With respect to the issue of promoting competition in generation markets, one thing is clear: the competitive bidding proposal as presented by the Commission does not require transmission access to succeed. The large number and wide range of generation proposals which have resulted from utility competitive bidding solicitations to date are evidence of this fact. If any efficiencies might be achieved by promoting competition to supply electric utility power needs, they would be distorted by conditioning competitive bidding on transmission access. These inefficiencies would be exacerbated if there is exclusive reliance upon embedded cost pricing for transmission services. Several of the parties advocating mandatory transmission access suggest, however, that such access should be priced based on "the costs of service" (presumably embedded costs),[6] while others have not articulated pricing principles for transmission services.

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[5] NOPR at 82.

But the promotion of competition in generation is not even the primary purpose of competitive bidding. As the NOPR indicates:

> Although bidding may result in increased competition, this is not the primary purpose of bidding. Rather, the principal objective of bidding is to further the purposes of PURPA by affording nonregulated electric utilities and state commissions an alternative means to price QF power, to promote equitable rates for consumers and the efficient use of facilities and resources by electric utilities, and to prevent discrimination against QFs.[7]

The NOPR goes on further to say: "[a] bidding system that does not provide for increased transmission access should accomplish these objectives without necessarily altering the status quo with regard to QFs' access to transmission services."[8] As we discuss further in this Appendix, conditional access to transmission is not only unrelated to the primary purpose of bidding, it is counterproductive to the efficiency goals of bidding.

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[6] See SAB Memo and Electricity Consumers Resource Council, Electricity's Future, (July, 1987).

[7] NOPR at 81.

It is difficult, inappropriate and counterproductive to address wheeling in the competitive bidding context: (1) without a simultaneous review of bulk power markets more broadly, (2) without addressing problems with respect to transmission capacity limitations and the ability to overcome such limitations, (3) without addressing the appropriate pricing of transmission services to ensure efficient markets, (4) without careful review and development of a record on the considerable legal issues involved, and (5) without a thorough assessment of the potential reliability implications. At the very least, the Commission need not and should not address conditional access until further experience is gained with the results of competitive bidding. All of these issues are discussed in detail in the following sections.

It is important to note that, according to the NOPR discussion, neither form of conditioned access (wheeling in or wheeling out) would involve transmission services for retail customers.[9] Thus, EEI's comments focus solely on the issue of conditioning competitive bidding on wheeling from sources of generation to wholesale markets.

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[8] NOPR at 81-82.

[9] NOPR at 87, n.125.

II. EFFICIENCY AND RELIABILITY WILL BE FURTHERED THROUGH VOLUNTARY TRANSMISSION ACCESS USING APPROPRIATE PRICE SIGNALS

FERC's goal of promoting efficiency through the use of competitive bidding will best be achieved with voluntary transmission access using appropriate flexible pricing mechanisms, and not by conditioning competitive bidding on mandatory wheeling. This approach will provide efficient price signals and promote voluntary, negotiated arrangements that are tailored to the individual needs of utilities and their customers while ensuring reliable service.[10] The importance of appropriate flexible transmission pricing in promoting efficiency is recognized in the economic literature and in recent Commission decisions.[11] However, such flexibility is not generally desired by those who seek mandatory transmission access, nor is it likely to be achieved if the Commission mandates access as a condition of bidding. The panoply of issues which must be addressed, including pricing in the broader bulk power markets, transmission supply constraints and means to overcome them, and appropriate pricing and associated terms and conditions for wheeling service, are not before the Commission in this proceeding. To address any of these issues without consideration of all of the others would result in undermining the efficiency goals which the Commission seeks to achieve in the context of this NOPR.

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[10] Pricing of Transmission Services in Bulk Power Markets, Factors for Consideration, EEI Transmission Technical Access Task Force (December 1987).

[11] Baltimore Gas & Electric Co., 35 FERC, Par. 61,150 (1986); Pacific Gas & Electric Co., 38 FERC Par. 61,242 (1987) (hereafter Western Systems Power Pool or WSPP); Pacific Gas & Electric Co. 42 FERC Par. 61,406 (March 31, 1988), modified in part, 43 FERC Par. ___ (1988) (hereafter PG&E/Turlock), Pacific Gas & Electric Co., ___ FERC ____ (Docket No. ER88-3-2-001) (July 5, 1981) (hereafter PG&E/Modesto).

Traditional economic regulatory policies have not always produced appropriate transmission price signals. Historically, transmission service rates have been based on embedded costs--the original cost of building existing transmission systems.

However, embedded cost rates tend to understate the costs of providing transmission service and do not allow pricing flexibility. For most systems, the embedded costs of transmission capacity is less than the cost of new transmission capacity. Thus, a new service that requires an expansion of transmission capacity will be priced below the true cost of providing such service. Embedded costing procedures, as traditionally applied, also ignore or understate various generation-related costs associated with transmission services, which may be quite significant. This issue is particularly significant when dealing with transmission of generation additions for and to third parties (as we are here) since traditionally, transmission has been built to serve the needs of a utility's native load customers. A fundamental tenet of transmission pricing policy should be that native load customer rates are not increased as a result of transmission services for third parties, from which native load customers receive no commensurate benefit.

Although the costs of providing transmission service differ from one system to another and from one kind of transaction to another, the types of costs incurred in providing transmission service may include some or all of the following:

(1) Transmission service costs. Costs of all the facilities required for the service involved, including current cost of new facilities that the service may necessitate.

(2) Transmission operation and maintenance costs. Primarily labor costs associated with functions such as supervision and engineering, load dispatching, station expenses and maintenance of structures, station equipment, and overhead and underground lines.

(3) Distribution costs (where applicable).

(4) Distribution operating and maintenance costs (where applicable).

(5) Administrative and general costs allocable to the transmission service.

(6) Costs of additional generation to cover losses. Fuel cost of generation to cover transmission losses, recognizing that transmission losses of a particular service may vary significantly from average transmission losses over a system. It may also include some component of capacity costs for the generation and transmission capacity required to cover additional loss burdens.

(7) Cost of reactive power/voltage control necessary to maintain proper voltage levels on the system.

(8) Cost of additional spinning reserves, including fuel cost plus incremental operating and maintenance costs.

(9) Cost of flow regulation.

(10) Cost effect on economic dispatch. Increased fuel cost that may result from the need to alter the

interchange scheduling and/or economic dispatch of utility power sources as a result of the transmission service.

(11) Opportunity cost. This represents the maximum net revenue or savings that a utility could obtain if it employed the transmission facilities used to provide transmission service for some other purpose, such as the purchase or sale of coordination power or other transmission transactions. Opportunity cost reflects the highest value alternative use of existing facilities.

Many of these costs are not accounted for in traditional methods of embedded cost pricing for transmission service.

Even generation and transmission pricing in competitive coordination markets, which FERC Commissioner Stalon has characterized as a "rather awkward hybrid between cost-based and market-oriented concepts,"[12] still constrains efficient transactions because of its inflexibilities. For example, traditional pricing for transmission services (provided in coordination markets) does not reflect the financial losses in the form of unrealized revenues or savings that may occur when transmission facilities are unavailable for opportunity sales and purchases.[13]

Moreover, traditional pricing fails to reflect supply and demand conditions accurately. The availability of "surplus" transmission capacity can change from hour to hour. The fact that transmission capability is available at a particular point in time does not mean that there is transmission capacity available for a transaction which may require such capacity at other times. Pricing of transmission capacity at embedded costs does not differentiate between conditions of capacity availability and capacity shortages. Priorities for use of available capacity, particularly to serve third parties, must be established. Where available transmission capacity is scarce, taking into account the actual time periods in which transmission will be needed, and after accounting for the needs of native load customers, traditional pricing fails to allocate this scarce resource to other users who give it the highest value. Nor does it provide transmission owners with incentives to provide third-party transmission services over the existing system, or expand transmission capacity where needed.[14]

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[12] Testimony of Commissioner Charles G. Stalon before the Committee on Energy and Natural Resources, United States Senate (February 1, 1988) at 33.

[13] The Commission recognized the significance of such losses in WSPP, at 61,797.

Various costing concepts provide efficient pricing alternatives to the traditional transmission pricing regimen. Appropriate costing concepts would include short-run marginal cost, long-run marginal cost, opportunity cost, market-based rates, embedded cost, value of service, and any combination of these which are consistent with the service and conditions involved in a particular transaction, and which prevent system reliability degradation. For example, long-run marginal cost concepts may be appropriate to long-term firm transactions which create additional capacity requirements, while short-run marginal cost concepts (which include opportunity costs) may be more appropriate to spot, non-firm transactions.

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[14] WSPP, at 61,796-797.

To increase the efficiency of bulk power markets, particularly as they become more competitive, EEI recommends that the Commission develop policies which rely upon appropriate economic concepts to establish a "zone of reasonableness" which provides the maximum flexibility for negotiating rates, terms and conditions appropriate to specific transmission services. Allowing pricing flexibility within this zone would promote two aspects of efficiency--it would allow prices to change quickly in response to rapidly changing conditions and it would allow prices to reach market clearing levels, thereby directing service to the buyers who value it most.[15/] Such pricing policies should also provide compensation that is fair to the native load customers of the wheeling utility and provide proper incentives for the provision of transmission services and the expansion of transmission capacity.

While the Commission's recent decisions in the Baltimore Gas & Electric, Western Systems Power Pool, PG&E/Turlock, and PG&E/Modesto cases have moved towards encouraging necessary flexibility in transmission pricing, at least for some types of services, the Commission has yet to articulate generally applicable guidance for establishing the boundaries of a "zone of

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[15/] See WSPP, at 61,790.

reasonableness" based on appropriate economic concepts which would permit more flexible transmission pricing.

Many proponents of conditioning competitive bidding on mandatory access appear to prefer relying upon traditional embedded cost pricing for such access because they recognize that embedded costs, particularly of transmission service, are typically lower than the true marginal costs of such services wherever there is a shortage of available transmission capacity. Even those who would support mandatory access based on other cost concepts may believe that a mandatory system is likely to emphasize simplicity in application, ignore costs which are difficult to identify, and thereby price transmission services below the economically appropriate level.

A transmission requirement that; (1.) that fails to reflect appropriate economic concepts, (2.) fails to provide appropriate incentives to utilities and their customers, (3.) is not tailored to the individual situation found in offering transmission services, and (4.) impedes the utility's ability to schedule and control its transmission system, subverts the efficiency objectives of competitive generation markets because it:

- Encourages the construction of new generating plants that might not otherwise be built or which are built at locations that would not be economically justified if transmission services were properly priced. Furthermore, the construction of such generation could displace other generation options with lower overall costs;
- Leads to under-investment in transmission capacity in cases where prices do not reflect true costs;
- Provides disincentives for transmission owners to negotiate transmission agreements where capacity is available, or to build new transmission

capacity that may be required to ensure efficient bulk power markets;

- Imposes cost burdens on the native load customers of the utility offering the transmission services who receive no benefit from third-party wheeling transactions and provides inappropriate price signals to potential users of the transmission system;
- Unfairly accounts for the costs incurred by the utility providing the service;
- Unfairly improves the competitive position of parties receiving an underpriced transmission service;
- Places significant and costly burdens on regulators to allocate limited transmission capacity among competing demands, and;
- Could jeopardize reliability if the transmitting utility loses the ability to schedule and control use of the network.

On the other hand, the development of transmission service pricing guidelines, based on appropriate economic pricing concepts, will go a long way towards securing the voluntary provision of services which efficiently allocate resources and are consistent with the needs of both utility and non-utility power suppliers. Such an approach is far more beneficial than the imposition of additional governmental regulation, which would be counterproductive to the development of efficient and reliable bulk power markets.

III. CONDITIONED MANDATORY ACCESS WOULD PRODUCE INEFFICIENCIES, CONTRARY TO THE GOALS OF COMPETITIVE BIDDING

FERC has stated that the goal of competitive bidding and relaxation of regulation for independent power producers is to increase efficiency in electric power generation markets and replace (on a voluntary basis) administrative determinations of avoided costs. Those groups and individuals who have advocated that competitive bidding must be conditioned on mandatory access to the transmission system have based their arguments on two propositions. First, that mandatory access is necessary to ensure optimal efficiency in generation markets under competitive bidding, and second, that competitive bidding without access will lead to undue discrimination in violation of the Federal Power Act or PURPA. The discrimination issue is discussed later in this paper. This section addresses the efficiency arguments of those advocating mandatory transmission services, which we believe would produce exactly the opposite result in many cases.

The two proposed forms of conditioned "wheeling" raise questions concerning whether they would actually improve economic efficiency, as well as related technical questions regarding how mandated "wheeling" could be performed within the existing framework of utility system operations. Some of these issues are common to both forms of wheeling, while others relate to one or the other, as presented in the following sections.

A. Issues With Respect to Both Wheeling In and Wheeling Out

1. Conditioning Competitive Bidding For Generation On Mandated Transmission Services Would Lead To Inefficient And Otherwise Detrimental Results.

Without efficient transmission price signals, conditioned wheeling could lead to inefficient locational decisions which do not take into account the true costs imposed by transmission requirements. A power supplier faced with price signals for transmission services which are based on embedded costs would have no incentive to make a locational decision based on the real costs imposed on the transmission network.

In addition, requiring utilities to provide transmission services for the successful bidder as a condition to the utility's participation in bidding for the needs of another utility (wheeling in), or by the host utility for those generators within the host's territory that lose in a bidding process in which the utility bids to meet its own needs (wheeling out) could provide disincentives for utilities to initiate bidding systems which include non-QFs and/or to participate as bidders. This is especially true where transmission requirements would be burdensome and lack the appropriate pricing incentives. In many parts of the country, it is infeasible to construct additional transmission lines due to the lack of or cost of rights-of-way. In such cases, requirements for transmission service would be especially burdensome, and would provide strong disincentives to bidding. Thus, conditional wheeling requirements could reduce the options available to utilities for future power supply, rather than meet what we believe are the intended policies of increasing power supply options.

2. The Rights Of Native Load Customers And Of Other Utilities For Limited Transmission Capacity Need To Be Addressed.

FERC suggests that both "wheeling out" and "wheeling in" would be required subject to reliability and economic dispatch considerations, yet offers no further explanation.[16] The NOPR does not discuss the rights of native load customers vis-a-vis other potential users of limited transmission capacity. Transmission is constructed for (and paid for in the rates of) native load customers. Although it is not entirely made clear in the NOPR, any third party transmission service should only be provided using transmission capacity which is excess to the reliability needs of native load customers for the full duration of the period in which transmission is sought.

Although a utility participating in a bid would need to ensure that transmission capability were available for its own bid, other bidders will probably be in different locations than the plant which the utility plans to use. Thus, the other bidders are likely to affect different transmission paths where adequate capacity might not exist. Even if the utility and non-utility bids were based on plants at the same or similar locations, differences in the characteristics of the facilities which are bid could have very different effects on the transmission system. For example, a facility under utility dispatch and a non-dispatchable facility at the same location would have very different effects, and impose very different costs on the transmission system. Furthermore, other bidders may seek transmission services under very different terms and conditions than the utility contemplated in its own bid. Thus, one can not say that because a utility participates in a bid, transmission capacity is, a priori, available for any other competing supplier.

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[16] NOPR at 87, 89.

Both wheeling in and wheeling out would most likely involve long-term, firm wheeling services. Transmission capacity availability is likely to change over the long-term--availability today does not mean availability tomorrow. In fact, loadings on the transmission system change from hour to hour. Furthermore, the magnitude of possible intersystem transfers of power is more apt to be limited by the transfer capability of the interconnection facilities than by the transmission lines themselves. In a given hour, the utility may not be conducting any transaction with a particular interconnected utility; and the entire transfer capability of such interconnection facilities therefore may be "surplus" and available. The next hour, native demand may increase or the utility may wish to conduct a transaction for the benefit of its native load customers, the implementation of which would totally load the interconnection facilities. Those facilities no longer are available for others. Such changes in transmission availability are a routine occurrence, taking place daily.

Moreover, particularly in the case of wheeling out, the amount of power which is sought to be wheeled could be far greater than the amount of power which is sought by a utility in its competitive procurement process. Conceivably, some bidders could not be taken on as long-term transmission service customers at all. In these situations, restrictions on the utility's available capacity would probably require allocation of limited capacity through some establishment of priorities for wheeling service among bidders. How would such priorities among bidders be established? In addition, there inevitably would arise occasions when some, but not all, of the transmission services being provided to bidders would have to be interrupted to preserve reliability of the wheeling utility's system. The proposal does not address how priorities for interruption among bidders might be established. In fact, such priorities would be difficult to establish and would likely lead to significant disputes.

Furthermore, to protect the reliability of the utility network, transmission of long-term firm power would likely require either upgrading of transmission capacity or construction of new lines at some time during the duration of the transmission service. First, a utility which is mandated to wheel would be expected to provide this transmission expansion. However, when the expansion is required, it is quite possible that the utility might be unable to build a new line because of siting and certification problems. In many areas of the country today, rights of way are becoming increasingly difficult to obtain. If the utility can not expand transmission capacity, than the utility (or perhaps regulators) will be left in the uncomfortable position of deciding who's customers will have to bear the reliability effects. It must be noted in this regard that the authority of FERC to mandate transmission system modifications is extremely limited.

Second, the siting and certification process for new transmission lines can be quite lengthy. If a utility which has been mandated to provide transmission access, and which requires an expansion of the transmission system to accomplish such service, cannot complete the siting, certification and construction process in the time frame needed by the bidder, who is liable for the financial (or other) penalties which would result? Can an unsuccessful bidder (in the case of wheeling out) rely on the ability of the wheeling utility to expand its transmission system in making a new bid to another utility? If such a reliance is not possible, would it ever make sense for another utility to purchase from that particular entity when transmission can not be assured? What if a particular state does not want the utility to expand transmission to serve an unsuccessful bidder, which wants to serve a utility in another state?

In operational ways, the proposal would also often frustrate the desired goal of economic efficiency and overall reliability in bulk power markets. Problems would arise in the relationships between the successful (wheeling in) and the unsuccessful (wheeling out) bidders on one hand, and other bulk utilities seeking wheeling of coordination or economy transactions on the other hand. The transmission and transfer capabilities of the utility that must provide mandatory transmission services could well be loaded with the required load of bidders. Could the original utility interrupt those services when it desired to conduct its own transactions over its own facilities (again, for the benefit of its own customers)? What liabilities would a utility accrue from such interruption?

As an example, take the situation where as the result of bidding on the needs of another utility, a utility is required to provide transmission for all successful bidders. The utility which is conducting a bid will be relying on the power provided by successful bidders to meet its own reliability requirements. Thus, any interruption of that power which is required by the transmitting utility to preserve its own reliability for its native load customers will affect the reliability of the utility needing the transmitted power. This potential conflict is a major reason why traditionally, electric utilities have limited their reliance on wholesale purchase sources to meet their reliability needs. Even in power pools, which rely heavily on bulk power exchange, power pool agreements usually provide that pool members are able to meet their own system loads without reliance on purchases from other pool members.

Furthermore, the case often arises where another interconnected bulk utility seeks transmission service, through the original utility, to a third bulk supplier. It is possible that the provision of such service is more profitable to the original utility and its native load customers, and the overall desired power transaction among the three bulk utilities contributes more to the economic efficiency and reliability of the region's power supply than would the mandatory transactions for other bidders. But the fact that other transactions have been mandated may preclude a utility from taking advantage of using its transmission system for more efficient opportunities.

In such situations, would the original utility be able to select among all available transmission transactions, or would bidders receive preferential status as a condition of the bidding process, regardless of the relative efficiency of the transaction?

These problems are exacerbated, again, by inappropriate transmission pricing. As we discussed in Section II above, transmission pricing must be based on economic concepts most appropriate to the terms and conditions of the transaction involved. Exclusive reliance on embedded cost transmission pricing policies will not provide appropriate price signals, nor give utilities appropriate incentives to expand transmission capacity to meet added demands of other bidders. Reliance on traditional embedded cost pricing policies would often require a utility's native load customers to subsidize transmission services for third parties, from which they receive no benefit. For example, customers of the wheeling utility will face foregone opportunity costs if wheeling for others reduces the ability of the utility to take advantage of short term cost saving opportunities in coordination markets.

All of these factors taken together suggest that conditioning competitive bidding on mandatory wheeling would provide significant disincentive for a utility to participate in bidding, either for the needs of other utilities[17] or for its own needs. If the utility loses the ability to choose to use its transmission system for the benefit of its own customers as a result of bidding involvement, or if it loses the ability to bid itself on future procurements as a result of losing transmission capability to others, than it may very rationally choose either not to bid or not to conduct bidding which includes non-QFs (which, as stated in the main body of EEI's comments in this docket, must be an option) -- even if it were otherwise likely or beneficial to do so. Again, this would be a result contrary to the desired result of increasing future power supply flexibility.

3. Conditioning Competitive Bidding On Providing Transmission Services Will Not, By Itself, Improve Efficiency In The Generation Sector.

The often stated purposes of all source competitive bidding is to provide a more market based approach to procurement of a utility's future power supply and to replace administratively determined avoided cost with a more effective approach.

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[17] William Berry, Chairman of Dominion Resources (the parent company of Virginia Power) has been quoted as expressing his belief that just the existence of the "wheeling in" proposal in this NOPR has reduced the level of competition in Virginia Power's recent solicitation, in that potential utility bidders have been frightened away because of potential effects on their transmission systems. Electric Utility Week (June 20, 1988).

ELCON and others[18] have claimed that mandatory wheeling requirements are a necessary pre-condition for increased competition in the bulk power markets. But mandatory wheeling as a condition of competitive bidding would occur in the context of continued price regulation of current generation, and thus will not necessarily provide any efficiency gains. In fact, mandatory transmission of power sales, priced at regulated cost-of-service rates is inconsistent with the notion of competitive bulk power sales based on market prices. If traditional inter-utility bulk power sales remain regulated based on cost of service, then the effects of competition (based on "market" prices) in sales from new generating sources will not necessarily lead to an efficient result.

For example, an inter-utility bulk power sale could have a lower marginal cost than a QF or IPP "market" sale price but a higher embedded cost rate. In this situation, requiring wheeling of the higher cost power will lead to higher customer costs.

The intent of the competitive bidding NOPR is not to introduce competition in the bulk power markets, but rather to introduce competition in the selection of future generating sources by an individual utility. As FERC itself concludes:

> Although bidding may result in increased competition, this is not the primary purpose of bidding. Rather, the principal objective of bidding is to further the purposes of PURPA by affording nonregulated electric utilities and state commissions an alternative means to price QF power, to promote equitable rates to consumers and the efficient use of facilities and resources by

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[18] e.g., ELCON Memo, SAB Memo.

> electric utilities, and to prevent discrimination against QFs. A bidding system that does not provide for increased transmission access should accomplish these objectives without necessarily altering the status quo with regard to QFs' access to transmission services.[19]

Providing transmission services for successful (wheeling in) or unsuccessful (wheeling out) bidding entities would not necessarily increase either competition in the bidding process or efficiency resulting from such competition, and, in many cases, would not even relate in any manner to the bidding.

Where bidding occurs within a centrally dispatched power pool or highly coordinated system, which generally characterizes the U.S. interconnected grid, conditioned transmission will result in no efficiency gains. The same generation would be used, regardless of what utility within the pool or coordinated system selects the capacity in a competitive bidding system. At the same time, however, a particular generator might disrupt centralized economic dispatch if a utility is required to transmit power from that generator to a purchaser outside the power pool.

With respect to QFs, their location is often limited either by the location of a particular resource or steam demand. But keeping in mind that the stated purpose of competitive bidding is to "more accurately develop avoided cost prices" for QFs, mandatory wheeling would not necessarily lead to a better estimate of avoided cost. In the case of wheeling in, a QF could end up providing a service to the non-local procuring utility regardless of whether or not efficiency would be better served by the local utility purchasing its output. In the case of wheeling out, a QF could decide to submit a "sham" losing bid so that its power could be sold elsewhere, again without regard to an efficient result.

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[19] NOPR at 81-82.

With respect to non-QFs, they will in many cases have locational flexibility. A mandatory wheeling requirement, as previously discussed, may simply distort the economics of location decisions by non-QFs. Given constraints on transmission capacity and the difficulties in expanding existing capacity, it makes no sense to provide incentives to non-QFs to locate in areas where transmission by other utilities would be mandated.

Provided that a particular transmission service would not affect reliability nor harm a utility's native load customers, there is absolutely no reason why a utility would not voluntarily provide transmission service for a successful or unsuccessful bidder to another control area utility, once the bidding results have been determined. Some may claim that a utility will try to exact "monopoly profits" from such transactions through pricing policies, but such a claim is, first, unrelated to the voluntary or mandatory nature of transmission service, and second, is fully within the realm of FERC regulatory authority to control.

4. In Wheeling Among Bulk Power Utilities, Interconnections Between Supplying And Wheeling Utilities Are Controlled To Ensure Constant Balancing Between Supplies And Demand. Such Control Could Become More Difficult To Maintain Under Conditioned Wheeling Scenarios, Particularly Those Involving A Large Number Of Individual Generators.

Where power production varies considerably over time (for example, as a QF's own load or steam requirements vary), varying quantities of power will flow across the wheeling utility's system as the power producer's operating conditions dictate.

On the other end of the wheeling transaction arrangement, the wheeling utility's interconnection with the receiving utility will be part of a controlled set of interconnections. In order to keep supply and demand for electricity balanced at all times, the wheeling utility must be able to ensure that power coming into its control area plus its own generation, less power flows out of its control area, is always matched to its load. Unless the purchasing utility is able to adjust its generation to instantaneously match a supplier's generation, then the purchasing utility will not receive power of the same quantity and quality that it is assumed to be purchasing.

In a wheeling transaction which involves three bulk utilities (a seller, transmitter, and purchaser), each operating a control area system, the generation of the supplying utility is controlled as to its output so that generation and load, taking into account power flows, are kept in balance.

Next, in interconnected operation of two or a multiplicity of interconnected systems, the interconnection flows are metered and telemetered to their respective control computers. It then is the computer matching of such actual interconnection flows to scheduled flows which achieves the essential balancing of each utility's generation to its own load on a moment-to-moment basis.

The power output of QFs, and possibly of some non-QFs, would not necessarily be similarly controlled by means of a dispatch or control computer. The output of a cogenerator, for example, could be, at any given moment, the excess of its generation over its own load. Notwithstanding the contractual arrangement between the supplier and purchaser, the cogenerator's output over its load is what will physically flow into the host utility's system. And that excess will not always be a constant quantity of power over any appreciable period of time.

But when an uncontrolled generator is substituted for a control area utility as the supplier, there may not always be a means of controlling the power flows from the producer into the system of the wheeling or host utility. Small producers are particularly unlikely to want to provide and install the control computers, the interconnection metering, and the telemetering necessary to provide such control because of the expense involved. Moreover, in the case of wheeling out, the proposal does not appear to allow utilities to require any degree of control from the unsuccessful bidders for whom they would have to wheel, (while, ironically, the NOPR suggests that utilities could require such control from winners of bidding). Without such control, the non-utility supplier would have no way of controlling, and the wheeling utility would have no way of knowing in advance the quantity of power which would be delivered into the system of the wheeling utility. Therefore, the wheeling utility could not know what quantities of power it was required to deliver to the receiving utility; and the wheeling utility would not know how to set its control computer to complete the transaction with the receiving utility. At the very least, the wheeling utility would have to provide generation services, increasing the overall cost of the transaction.

The problems described above are exacerbated if the purchaser signs a take-or-pay contract with the supplier (over which the wheeling utility would have no say.) In that case, even if the supplying generation is controlled, any control of that generation could either result in a financial penalty to the purchaser (the purchaser would have to pay for power that wasn't actually delivered,) or in a loss of flexibility to the utilities involved to balance generation and load in a least cost manner.

5. "Wheeling In" And "Wheeling Out" Would Complicate System Planning And Operations.

The necessity to provide access to a potentially large number of generators, at undetermined locations and under terms and conditions which cannot be known in advance, would make system planning and operations more complex and uncertain, with potential deleterious effects on reliability.

Utilities plan their transmission systems well in advance of need, based on connecting existing and planned sources of generation with load centers. Utilities also plan and construct interconnections with other utilities to provide greater reliability at lower overall system costs. When utilities plan transmission lines and interconnections, they build in a certain reserve margin so as to meet emergency "contingencies." These margins ensure that utilities can lose one or more transmission lines without system-wide breakdowns when faced with emergencies.

The transmission system can not be adequately planned without reasonably accurate advance knowledge of the location of future generating sources and loads. As explained by Appendix B to these comments, reliance on a large number of new suppliers seriously complicates transmission planning and imposes reliability risks. The introduction of mandatory transmission requirements would mean that the utility would have to plan its transmission network without knowledge, at least very far in advance, of potential users of its transmission system. Thus, transmission capacity planning would become extremely difficult and uncertain. Given the problems in siting new lines and in many cases, of obtaining right-of-way, it would be difficult, if not impossible to construct such lines on speculation. Even if it were possible, shortages of transmission capacity in some areas and surpluses in other areas are likely to result, with the effect being a waste in valuable resources and capital.

With respect to the existing system, any new generation on the network will change the pattern of power flows throughout the network, and might even cause problems for other utilities which are not a part of the transaction because of loop flows. At the very least, utilities must be able to deny access to generation sources which have such locations and other characteristics which could jeopardize reliability.

Furthermore, while utilities may have a margin of capacity which is built into the system to meet contingencies, the use of this margin for third-party transmission services will potentially reduce the level of reliability which a utility can provide to its native load customers. In this context, reliability refers to system reliability, as opposed to the reliability of particular generation, transmission or distribution components of the system. Any adverse impacts on system reliability will have effects on individual customers. Even if the system is not overloaded by such transactions, customers may face an increased probability of system outages. In other words, the utility may no longer be able to use its margin of capacity to meet system emergencies. This problem will be exacerbated if the utility is unable to control and/or interrupt a generating source's output when it faces emergencies or unusual conditions. Operating margins are exactly that and can not be used for firm transactions, without undermining the reliability of service to customers which such margins were designed to provide.

6. The NOPR Is Ambiguous As To Requiring Transmission To A Utility's Wholesale Requirements Customers, Which Would Have The Same Effects As Retail "Bypass."

The combination of FERC's competitive bidding guidelines and conditioned mandatory wheeling might be construed to allow successful or unsuccessful bidders to require a utility to wheel from such a bidder to one of the bulk power utility's own wholesale requirements customers. For purposes of this discussion, by wholesale requirements customers, we mean entities purchasing all or part of their power requirements for resale, which are located within the control area of a bulk power utility, and which do not have their own control area. But the Commission is somewhat ambiguous on this issue. The NOPR states:

> It is important to draw a distinction between two fundamentally different kinds of transmission access: "supplier access" and "customer access." "Supplier access" involves rights for suppliers of electricity of access on reasonable terms to utility transmission grids to reach wholesale markets beyond the native utility. "Customer access" involves the ability or right for retail or wholesale requirements customers to gain transmission access to reach suppliers other than their native utility, or for such suppliers to reach the retail or wholesale customers of another utility. "Customer access" raises serious concerns as to its potential affects on both the financial viability of franchised utilities and protection of their customers. See Statement of Commissioner Charles Stalon before the Senate Committee on Energy and Natural Resources, February 1, 1988, pages 36-41. Because "customer access" involves issues relating to retail electricity services, the Commission is not requesting any comments relating to "customer access."[20]

Initially, customer (both wholesale and retail) access is described as causing serious concern, but in the last sentence of the above quote, the Commission has referred only to retail access. We assume that this apparent inconsistency was inadvertent, for there is no difference in impact between the wholesale and retail customer bypass issue. The same principles which FERC has annunciated with respect to a utility's retail customers apply to its wholesale requirements customers.

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[20] NOPR at 87, n.125.

If a wholesale requirements customer conducted a bidding process, and if its supplying control area utility wanted to continue to serve that customer, it would have to participate in the bid and wheel to its own customer if it loses. These problems would be exacerbated even further if, as EEI fully discusses in its comments on the IPP Notice of Proposed Rulemaking, the utility is precluded from competing to serve that requirements customer on the same basis as other competitors because it happens to own the transmission necessary to serve that customer. The utility supplier to such a wholesale customer is thus placed in an absolute "Catch 22".

The problem that this scenario creates is that in many cases, competitive procurement or "shopping" by wholesale requirements customers raises the same issues and has the same negative impacts that would occur with retail shopping or bypass. Regardless of whether or not a utility has a statutory obligation to serve such wholesale customers, it has a very real and practical obligation. A requirements customer is located within the control area of its supplying utility, and does not typically have a control area of its own (nor any or little of its own generation to control). The implications of this fact are that if generation provided by a supplier other than the control area "host" utility does not exactly match the load of the customer, the control area utility where the purchaser is located will be providing that power or any differences.

The control area utility could of course be compensated for generation services (but the measure of such compensation presents complex issues not even identified in the NOPR). Even then, however, the control area utility would have to provide back-up capacity to the off-system generation source while the requirements customer is purchasing off-system. The control area utility's remaining customers might be required to pay for that capacity when it isn't needed. There is also the question of the capacity which a utility has already built to serve wholesale customers. If such a customer purchases from an off-system supplier, the remaining customers of the utility will face increased rates, as the fixed costs of resulting abandoned capacity will be spread over a smaller base of utility sales.

And what happens at the end of the contract that a wholesale customer has with an off-system source (in this case the successful or unsuccessful bidder)? Even if FERC allows the current control area utility supplier to provide service at a higher price, it will be faced with a load which it may not have planned for. Can that utility realistically refuse to provide service?

The wholesale service obligation issue is also clouded by the fact that FERC, in many instances, has not allowed a regulated utility supplier to terminate its requirements service, even after the expiration of the contract on which such service was based. Both in a technical sense and a traditional regulatory policy sense, it has been the wholesale customer purchaser who has had the option of requiring continuation of its requirements service. This has resulted in an implicit, if not explicit obligation to serve requirements customers.

In a recent case decided by FERC involving Pacific Gas & Electric Company and the Modesto Irrigation District, the Commission recognized this implicit obligation to serve wholesale customers and the complex issues involved, in stating:

> We recognize, however, that in the event Modesto has not arranged for adequate capacity to meet its own load, that power will still flow to Modesto over PG&E's lines. After all, "it is difficult to imagine that the Commission would allow a utility to terminate service to a full or partial requirements customer that has no alternative source of power simply because that customer has not adequately arranged for its own needs, when it is technically feasible to provide service of some sort." [Quoting Order 474, "Electric Rates; Construction Work in Progress; Anticompetitive Implication"] The practical issue, therefore, is not whether PG&E would continue to provide Modesto with power; it is the price PG&E can obtain for this last resort power.[21]

Thus, the Commission itself has recognized the practical wholesale service obligation, and some of the serious issues and concerns it raises with respect to wholesale customer bypass.

Wheeling over an intervening system requires that the purchaser reduce its generation to match the quantity and characteristics of the generation provided by the seller. But if the purchaser cannot control its generation, it is the generation of the wheeling utility which must be reduced. This is why Commissioner Stalon has so aptly described customer wheeling as the "wheeling of money" rather than power. The bidder who has wheeling service is in reality providing its power to the wheeling utility to replace that utility's generation, and the wheeling utility is really providing the generation required by the wholesale customer. But in this case, any monetary savings resulting from the transaction flow to the wholesale customer, in spite of the fact that the "wheeling" utility is still providing the generation as it did before the transaction.Thus, there are no efficiency gains from providing "wheeling services" to wholesale requirements customers.

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[21] PG&E/Modesto, Docket No. ER88-302-001, (July 5, 1988) at 18.

In passing the Section 211 and 212 amendments to the Federal Power Act when PURPA was enacted, Congress carefully considered and rejected wholesale customer bypass. The legislative history of PURPA is explicit that Congress intended to "narrowly define the purposes for which wheeling can be used," and that those purposes "would not include shopping around for power."[22] Congress knew that large-volume customers could use the utility transmission system as a weapon against residential and other small-volume customers, to allocate certain benefits to themselves at the expense of smaller customers.

In short, wheeling, whether to wholesale or retail customers, raises a panoply of issues and concerns, which we do not believe have yet been adequately addressed. Certainly, we believe that the record which will be developed in FERC's current series of rulemakings on ADFAC, Competitive Bidding, and IPPs will necessarily be insufficient to deal with this issue. Customer bypass must be considered only in a comprehensive manner as it relates to broader wholesale and retail market issues. Thus, wheeling in and wheeling out should be rejected on this basis alone.

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[22] Hearings Before the Subcommittee on Energy Conservation and Regulation of the United States Senate Committee on Energy and Natural Resources, 96th Cong., 2d Sess. (Committee Print, September 20, 1977) at 175 (Remarks of Senator Johnston)).

7. The Experience Of States In Mandating Transmission Services In The Competitive Bidding Context Or Otherwise Is Not Relevant To The NOPR Proposals.

While it is true that several states have asserted mandatory wheeling authority, not all of these states have instituted bidding. One of the primary rationales for this state authority has been an excess of cogeneration capacity in a particular geographic area which is not needed by the local utility. Of the utilities that have implemented competitive bidding thus far and have a state mandated wheeling requirement, none have "all source" bidding as envisioned by the FERC proposal, for which many additional issues are involved as noted elsewhere in these comments.

Furthermore, the competitive bidding programs to date were not set up under FERC's envisioned rules. Some state commissioners have said that their bidding programs might be illegal or not viable under the proposed state rules.[23] It is not clear that wheeling experience relevant to existing bidding programs is relevant in the context of the current FERC proposals.

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[23] See, for example, letter from Cheryl Harrington and David Moskowitz, Maine Public Utilities Commission, to Maine Congressional Delegation, et. al. (May 3, 1988).

It is also important to note that while states have established wheeling authority, we know of no cases where the states have had to use that authority to force utilities to wheel. The utilities involved have been able to negotiate wheeling arrangements with QFs without regulatory intervention. As stated earlier in the main body of our comments, the Commission should not act to disturb existing competitive bidding systems which are working well in the interests of regulators, utilities, and customers.

B. Issues With Respect To Wheeling Out

1. Serious Inefficiencies May Result Where A Patchwork Exists Of Utilities Using Competitive Bidding With Others Relying On Administratively Determined Avoided Costs.

With respect to QFs located in service areas using competitive bidding, a wheeling out requirement could give QFs an incentive to provide a "sham bid" with an artificially high price and the intention to lose to the local utility in order to get their power wheeled to a utility with a higher, administratively determined avoided cost (that utility being obligated to purchase QF power under PURPA). While such a deal may be advantageous for the QF, it will not contribute to overall efficiency. Non-QFs could, under some circumstances, have the same incentives if they expect that the price to supply a non-local utility which is seeking bids will be higher.

2. Wheeling Out Will Lead To Inefficiencies If Pricing Policies For Existing Utility Bulk Power Markets Are Not Changed.

A number of questions regarding the implementation of this proposal remain, for several of which the NOPR seeks comment. These questions actually point out many of the problems and inefficiencies that would result from "wheeling out" requirements. These questions include, first: When would the obligation to wheel out begin and end? Assumedly, the wheeling utility would have such a requirement imposed for the duration of any contract which the unsuccessful bidder signs with another purchasing utility. Otherwise, the bidder would not be able to sell to another utility, thus defeating the alleged purpose of wheeling out. The problem is that the duration of the contract between a losing bidder and another utility seeking power bears no relationship to the duration which was sought in the wheeling utility's original bid to supply its own needs. A utility which bids to sell power to itself for 5 years could become obligated to wheel power to another utility for 30 years.

The same issue holds true regarding the amount of capacity for which a utility could be mandated to wheel. A utility bidding 100 MW of capacity for its own needs could become obligated to wheel hundreds or thousands of megawatts. For example, the recent Virginia Power bidding solicitation resulted initially in bids totaling 13,900MW to satisfy 1,750MW of need. If Virginia Power had participated in its own bidding process, it could have at least in theory, been faced with a requirement to wheel up to 10,300MW of capacity, equal to that which was bid from within its service territory. Of course, not all of the capacity represented by those bids will find other purchasers, but even if only a small proportion were to, and Virginia Power had bid, that would have amounted to a substantial amount of capacity which would be required to be wheeled under the Commission's proposal.

Both of these cases provide further demonstration of the fact that wheeling out bears no relationship to the actual purposes or intentions of FERC's competitive bidding program. Also, in both cases, the utility could not know in advance of conducting its bidding process the amount or time duration of transmission requirements which would result. The uncertainties of wheeling obligations brought about by bidding could weigh heavily against a utility's electing to participate in or use bidding processes if it has a choice in this matter (which we believe it must). If state commissions believe that wheeling out would be detrimental to retail customers, they might preclude utilities from using bidding as well, either for QFs or all sources.

Second, would there be any limit upon the aggregate amount of "wheeling out," for which the utility would be committed as a result of participating in its own bidding process? While we believe that such limits would be absolutely essential, we do not know how such limits could be set or how that aggregate amount would be allocated among unsuccessful bidders. Would QFs have a preference over unsuccessful non-QFs, even if the non-QFs contributed more to overall efficiency? What about priorities even among losing QFs? Since one of the purposes of bidding among QFs is to prioritize them in terms of economic efficiency, it would be ironic (as well as arbitrary and capricious) to avoid such prioritization in allocating transmission capacity. Would FERC allocate the aggregate amount of available transmission capacity among unsuccessful bidders, recognizing that many of the wheeling transactions sought will be interstate in nature, or will that be a state or utility responsibility?

Third, should wheeling out be required to suppliers who do not bid? In a sense, suppliers who do not bid are not much different than suppliers that would submit "sham" bids. In either case, we see no economic efficiency or other purpose served. Such a requirement would simply provide a special benefit to certain suppliers, without necessarily any benefit, and with increased costs to the transmitting utility's customers.

3. Wheeling Out Provides No Benefit To Utility Customers.

Unsuccessful bidders seeking wheeling out will likely offer higher prices than the local utility's avoided cost (as determined by the local utility's bidding results). If the unsuccessful bidder is a QF, any utility to which the power is wheeled would likely have to purchase the QF's power at that utility's avoided energy and/or capacity costs. Economic efficiency would be served better if the local utility provides power to the neighboring utility at the local utility's own avoided costs. But under traditional FERC sales-for-resale pricing policies, the local utility may be constrained to selling to neighboring utilities at its own embedded costs. This points out the critical interface between bulk power market sales pricing, associated transmission pricing and transmission access issues such as wheeling out. Unless these issues are addressed together in a comprehensive manner, the attempted resolution of one area will lead to inefficient results in the other areas.

4. With Respect To QFs, The Mandatory Purchase Obligation, For Either Energy Or Capacity, Is Likely To Skew Efficiencies Under A "Wheeling Out" Scheme.

The goals of PURPA are to balance conservation, efficiency and customer equity. The wheeling out proposal, particularly without first ensuring appropriate pricing signals for existing bulk power sales and transmission services, will not accomplish these goals.

For example, cases could occur where efficiency is better served by a losing QF bidder providing energy to the local utility rather than selling capacity and/or energy to a neighboring utility. Although sales to another utility could be a better financial deal for the unsuccessful bidder, particularly when transmission services are underpriced, the FERC objectives should be to promote the efficiencies gained through competition, and not to protect individual competitors.

5. "Wheeling Out" Is Not Related To The Purpose Of A Bidding System Or Alleged Potential Discrimination.

Conditioning bidding on mandatory wheeling out will not necessarily increase the number of bidders (except perhaps those bidding with the intent to lose solely to gain access) or change the price of the winning bid. Wheeling out would only be required to unsuccessful bidders, who could not be determined until after the bidding process is complete. If a bidder competes with the expectation of winning, then the potential of gaining access to another utility will not increase the number of bids. Thus, there is no basis for the assertion that wheeling out will increase competition in bidding processes, nor as stated earlier, is it necessary or related to the determination of the avoided cost of the purchasing utility, which is the purpose of bidding.

An assertion has also been made by various parties that conditioning competitive bidding on mandatory wheeling out is necessary to remedy potential discriminatory practices against QFs, contrary to the legal requirements of PURPA.[24/] But as the NOPR itself points out, as long as all QFs have an opportunity to bid, there is no discrimination against them.[25/] Again, because wheeling out does not take place until after the bidding process is concluded, it does not affect the ability of QFs to participate in bidding. The same principles are true with respect to non-QFs.

[24/] See, for example, ELCON Memo, SAB Memo, and ELCON/CEPA Memo.

[25/] NOPR at 24. See Section IV.A.3. below.

6. The Intended Purposes Of Competitive Bidding, When Conditioned On Wheeling Out, Would Not Be Achieved.

PURPA was not intended to be a statute promoting bulk power market competition, but rather was intended to better utilize energy resources, among the other objectives previously stated. Nowhere does PURPA mention generation competition as an objective. In fact, the mandatory purchase obligation for sales from QFs under PURPA is antithetic to true competition. Even under competitive bidding, the mandatory obligation for energy purchases from QFs remains, as does preference for QFs in the case of a tie (as suggested by the NOPR). To the extent that "wheeling out" has been suggested by some as necessary to competitive bulk power markets, "wheeling out," combined with the QF mandatory purchase obligation would produce results contrary to the desired results of truly competitive markets. Essentially, the combination leaves QFs a choice of participating in bidding or selling at least energy to the local or distant utilities, without regard to the efficiency of the result.

C. Conflicts In The Definition Of Wheeling Out

The NOPR definition of wheeling out references testimony by Commissioner Charles Stalon before the Senate Energy and Natural Resources Committee, February 1, 1988 as its source.[26] However, in that testimony, Commissioner Stalon's definition of wheeling out differs from the definition offered by the NOPR. Commissioner Stalon, in his Senate testimony, referred to wheeling out as an obligation for a utility which procures power through competitive bidding to wheel power for all unsuccessful bidders. This definition differs from the NOPR in that it is unrelated to whether the utility seeking bids or its affiliate participates in the bidding procurement.

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[26] NOPR at 89.

EEI assumes that the definition of wheeling out for which FERC seeks comment is the definition provided in the NOPR. However, all of the arguments presented in this Appendix, as well as some additional arguments apply to Commissioner Stalon's alternative definition.

Perhaps most importantly, under this alternative wheeling out definition, wheeling would not be conditional at all. Under the Commission's competitive bidding proposal, the utility does not have the right to decide whether to conduct competitive bidding. The bidding proposal is voluntary for the state commissions, not for the utilities. There is no voluntary decision by the utility, so one could not suggest that transmission requirements can be made a part of some voluntary act. If the state orders a utility to conduct bidding, the utility would have no choice but to comply. If bidding is mandatory at the state level, and access is a condition of conducting bidding, then under this alternative definition of wheeling out, access is most certainly mandatory, not "conditional." The unlawfulness of FERC conveying authority to the states to mandate wheeling in such a manner is discussed in Sections IV.C. and IV.D. below.

D. Issues With Respect To "Wheeling In"

In addition to those issues mentioned previously which apply to both types of conditioned mandatory wheeling, "wheeling in" presents some additional unique issues. The stated purpose of "wheeling in" is to prevent purported abuses of monopoly power which could be present if a utility, controlling transmission needed by competitors, is itself a bidder. While one might imagine situations where a utility could refuse access to a competitor, sufficient remedies exist to prevent or deal with such abuses. A generic mandatory transmission condition unjustly assumes, before the fact, that abuse will occur. Mandatory transmission is not an appropriate solution to a problem which is only "presumed" for the future, with no basis in fact.

1. Conditioning Bidding On "Wheeling In" Incorrectly Assumes That Bidders Always Lack Sufficient Means Of Delivering Power To A Utility Which Solicits Bids.

"Wheeling in" assumes, a priori, that the transmission facilities of any bidding supplier in question would be necessary to provide other would-be bidders competitive access to supply the bidding utility. Such a finding cannot be made on a generic basis. First, transmission services may be voluntarily available, particularly if there is flexibility to enter into agreements based on appropriate prices, terms and conditions.

Second, it is important to remember that the only purchasing markets in question are utilities. Utilities are usually so interconnected that, with respect to almost any bulk utility market which could be identified, there usually are multiple transmission paths to reach the market. Third, many suppliers may be able to locate generation so as to avoid the need for wheeling.

2. FERC Can, Under Its Existing Rate Approval Authority, Ensure That Utilities Do Not Set Transmission Rates For Competitors In An Unduly Different Manner Than The Transmission Rate Components Of Their Own Bids.

An alternative approach to deal with FERC's concerns in this area might be to require utilities to incorporate in their own bids a transmission charge, along with the methodology, incorporated cost components, and terms and conditions associated with such charges. FERC could then assure that transmission rates offered to other competitors were based on the same methodology, cost components, and terms and conditions, except where differences could be specifically justified. This is not to say that transmission charges will be equivalent for all bidders--location of the bidder, transmission capacity needed, firmness and timing of transmission needed and many other factors will affect these charges.

3. If Multiple Utilities Bid On The Same Procurement, Will All The Bidding Utilities Have A Mandatory Wheeling Obligation For All Other Bidders Within And Outside Of Their Service Areas?

Assume that Utility A is directly connected to the purchasing utility, that B is connected to A, C to B, and D to C -- i.e., four utilities stretched out in a row. If A wants to bid, it must agree to wheel for B, if B is the successful bidder. If both A and B bid, presumably B must, in turn, agree to wheel for C, if C is the successful bidder. And so on, to include D.

One might hypothesize that the economics of the situation would specify where the string would be cut -- i.e., at some point the wheeling fees would preclude a more distant supplier from bidding. However, this would depend on the pricing of transmission services reflecting true economic costs. If regulation continues to keep transmission rates below appropriate price levels (less than true economic costs), there would not necessarily be any overall economic gain from the wheeling in requirement if it results in uneconomic purchases from distant utilities.

4. Advance Notice That A Utility Intends To Bid On The Needs Of Another Utility Will Not Likely Help Other Bidders Fashion Their Proposal, As The NOPR Suggests, Without Introducing Competitive Problems.

Even if a utility gave advance notice that it intended to bid, it could not set a prospective wheeling rate without knowing the specific location and characteristics of the other bidders. But other bidders would probably choose not to share such information with the utility with which it would be competing.

Nor, if the utility is a bidder, would it be fair for the utility to set out in advance the characteristics of its own bid. However, without information regarding the location and non-price characteristics of bidders, it will be impossible for the bidding utility to know whether transmission capacity will be available for particular bidders, and what costs the particular facilities will impose on the utility transmission system. Such information is in turn vital for the appropriate pricing of transmission services.

Furthermore, as discussed in more detail in Appendix B, the lack of information flow between bidders requiring future use of the transmission system and the utilities operating that transmission system will greatly complicate the transmission planning process, resulting in increased risk and uncertainty. Given the vital nature of transmission planning to reliable system operations, conditional mandatory access requirements should be rejected.

5. Difficulties May Arise If The Bidding Utility Is In A Different State Than The Utility Seeking Bids.

In this situation, any mandatory requirement for wheeling that results from one state instituting a bidding system will impact the transmission systems, and potentially generation, in other states. This could also be true even if the bidding and procuring utility are in the same state, but in different control areas. Any FERC proposal which gives states authority to either directly or indirectly mandate transmission has considerable technical and economic ramifications which need to be fully explored. In addition, as described in the next section, we believe such an action by FERC would be illegal.

IV. THE FEDERAL POWER ACT AND PURPA PROHIBIT THE COMMISSION FROM MANDATING TRANSMISSION ACCESS, DIRECTLY OR AS A CONDITION OF COMPETITIVE BIDDING, IN THE CIRCUMSTANCES CREATED BY THE PROPOSAL.

The Federal Power Act prohibits the Commission from mandating transmission services except in prescribed circumstances under Sections 211 and 212, which are not applicable in this proceeding. Whatever discretion the Commission may have to further the policies of the Act does not authorize it to evade that prohibition by claiming that transmission is a remedy for unduly discriminatory or anti-competitive conduct. Reliance upon an avoided cost standard determined through competitive bidding is as a matter of law, not discrimination or anti-competitive conduct, as could justify such a remedy. The Commission has made no finding that utilities have in other respects engaged in unduly discriminatory or anti-competitive conduct.

Further, attempts to evade the prohibition on mandatory transmission services, by claiming that the proposal would impose transmission as a condition of some other "voluntary" act by the utility, founder upon the fact that competitive bidding under the circumstances presented by the proposal is voluntary to the state commissions, not regulated utilities. If a state requires bidding, a utility would be forced to bid if it believes it can best satisfy the services required. If the utility does not bid, it could be deemed to have made an imprudent decision. To the extent that FERC has any authority to mandate transmission on a case-by-case basis, it cannot delegate such authority to the states.

There is also no basis for Commissioner Stalon's suggestion that Sections 210(a) or 210(f) of PURPA authorize mandatory transmission services. The Commission's discretionary authority to adopt rules to implement PURPA cannot be read to implicitly repeal the long-standing interpretation that the Federal Power Act precludes the Commission from broadly mandating transmission services, as in the circumstances suggested by wheeling in or wheeling out. The Commission has admitted that the Conference Report to PURPA shows that Congress did not draw fine distinctions between PURPA and the FPA. When Congress sought to grant FERC authority to mandate transmission services it did so exclusively and expressly in defined circumstances, by adopting Sections 211 and 212 of the FPA.

A. The Scope Of The Commission's Discretionary Authority Does Not Permit It To Exceed Clear Congressional Limits On Commission Action

The Commission lacks the legal authority to impose directly or indirectly any of the transmission conditions discussed in the proposal. The Preamble to the NOPR provides no discussion of the Commission's authority to implement the transmission access portions of the proposal other than to note "the Commission has broad discretion to impose conditions to further policies embodied in the statutes it is charged with administering."[27] The absence of any additional legal analysis of the sources or scope of the Commission's discretion raises a significant obstacle to our ability to comment effectively. Nevertheless, we have reviewed the Federal Power Act and PURPA and conclude that neither Act explicitly nor implicitly provides the Commission with such authority.

Whatever discretion the Commission may have to impose conditions which further the policies of the Acts it administers,[28] such discretion does not permit it to implement a remedy which Congress specifically excluded from Commission jurisdiction. All of the cases which the Commission relies upon in footnote 124 recognize that the Commission's discretion is bounded by the limits on its authority. In Niagara Mohawk Power Corp. v. Federal Power Commission,[29] the Court stated that:

> "necessary or appropriate" provisions ... authorize an agency to use means of regulation not spelled out in detail, provided the agency's action conforms with the purposes and policies of Congress and does not contravene any terms of the Act. (Emphasis added.)

Associated Gas Distributors v. FERC,[30] and American Paper Institute, Inc. v. American Electric Power Service Corp.,[31] each contain detailed analyses of the extent to which legislative history or other statutory provisions impose limits on the Commission's discretionary authority. These cases, too, implement the following principle articulated by the D.C. Circuit:

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[27] NOPR at 86, n.124.

[28] NOPR at 86, n.124.

[29] 379 F. 2d 153, 158.

[30] 824 F.2d 981 (D.C. Cir. 1987) (hereafter Associated Gas).

[31] 461 U.S. 402 (1983) (hereafter API).

> The allowance of "wide latitude" in the exercise of delegated powers is not the equivalent of untrammelled freedom to regulate activities over which the statute fails to confer, or explicitly denies, Commission authority.[32]

The applicability of the Commission's discretionary authority to mandate transmission services was explicitly addressed and rejected in Richmond Power and Light v. FERC,[33] In response to the energy crisis, a voluntary program including voluntary transmission rates was established to transmit coal-generated electricity from the Midwest to the East. The intervenors urged the Commission not to approve those rates unless the Commission attached a condition requiring greater transmission access. Those intervenors gave up arguing that FERC had the authority to mandate transmission directly.[34] Instead, they argued that, since the utilities had voluntarily filed rates for transmission services, FERC could condition approval of those rates on the utilities agreement to provide more transmission services than they had originally intended.

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[32] National Association of Regulatory Utility Commissioners v. FERC, 533 F.2d 601, 617 (D.C. Cir. 1976) (footnote omitted).

[33] 574 F.2d 610 (D.C. Cir. 1978).

[34] Id. at 619.

The court first noted, quite strongly, that FERC had no authority to require transmission services by direct order. The court then held as follows:

> In this court Richmond seeks the same end through less direct means. Since the Commission may reject unreasonable rate proposals and fix acceptable rates instead, and since the utilities submitted to the Commission rates for *voluntary* wheeling, Richmond asserts that the Commission must have the power to *condition* its approval of those rates on continued, albeit involuntary, wheeling. This logic is superficially persuasive: *the Commission does have authority to impose requirements and conditions "necessary or appropriate to promote the policies" of the Act. But such conditions may not contravene the Act, and the reasoning of Richmond's unstated minor premise, as we now explain, seeks to achieve just that*.
>
> Richmond assumes that the proffered rates were unreasonable because they did not guarantee that utilities will wheel. Yet Congress' as-yet unamended purpose was to indulge utilities that very freedom. If Congress had intended that utilities could inadvertently bootstrap themselves into common-carrier status by filing rates for voluntary service, it would not have bothered to reject mandatory wheeling in favor of a call for just such voluntary wheeling. *What the Commission is prohibited from doing directly it may not achieve by indirection.*[35]

Thus, the Commission's discretion to further the policies of the FPA does not allow it to evade the prohibition on mandatory transmission.

B. *The Federal Power Act Does Not Give The Commission Legal Authority To Compel Transmission Services As A Condition of Competitive Bidding*.

1. Prior To 1978, The Commission Was Prohibited From Mandating Any Transmission Services.

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[35] *Id.* at 620 (footnote omitted) (emphasis added).

Historically, the Commission has never had general authority to compel a utility to transmit power for third parties. When Part II of the Federal Power Act was originally drafted, the first draft contained provisions which would have required electric utilities to "transmit energy for any person upon reasonable request" and would have allowed the Commission to require such wheeling.[36] Congress deleted such provisions, and specifically wanted to insure that transmission would remain a "voluntary action of the utilities."[37]

For more than 40 years following the passage of the Federal Power Act, the law was clear that the Commission had no power to order a utility to offer transmission services.[38] Even where the utility's refusal to offer such services has been found to be a violation of the antitrust laws, the Supreme Court held that the Commission still did not have the authority to order that utility to "wheel." In Otter Tail Power Co. v. United States,[39] the Supreme Court stated that, although a court may order transmission services to remedy antitrust violations, the Commission itself may not. "So far as wheeling is concerned, there is no authority granted the Commission under Part II of the Federal Power Act to order it, for the bills originally introduced contained common carrier provisions which were deleted."[40]

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[36] See H.R. 5423, 74th Congress, 1st Sess.

[37] S. Rep. No. 621, 74th Congress., 1st Sess., at 19.

[38] Richmond Power and Light v. FERC, 574 F.2d 610 (D.C. Cir. 1978).

[39] 410 U.S. 366, reh. denied, 411 U.S. 910 (1973).

The Commission itself has agreed, stating:

> If wheeling means the obligation of one public utility to make its transmission facilities available to 'facilitate' a power supply contract between two other unconnected companies, ... we think the Commission *lacks* the power to order it, because Congress considered and affirmatively rejected a provision which would have made it the 'duty of every public utility to ...*transmit energy for any person upon reasonable request therefor*...' (emphasis in original).[41]

The circuit courts also agree that "[a]s originally enacted, the Federal Power Act did not permit the Commission to compel wheeling."[42] The law on this point is well settled: the original Federal Power Act did not allow the Commission to force a utility to offer transmission services.

2. The 1978 Amendments Gave The Commission Precisely Defined Authority To Mandate Transmission, Which Cannot Be Used In This Rulemaking.

Sections 211 and 212 of the Federal Power Act,[43] enacted as part of PURPA, granted the Commission specific authority to order transmission services under very detailed, specific criteria to promote reliability, conservation and efficiency, so as to reduce reliance on imported oil. These sections contain requirements which forbid the conditional transmission proposals and which, in any event, the Commission cannot meet through a generic rulemaking.

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[40] *Otter Tail*, 410 U.S. at 375 (footnote omitted).

[41] *City of Paris v. Kentucky Utilities Co.*, 41 F.P.C. 45, 49 (1969) (footnote omitted).

[42] *New York State Electric & Gas Corp. v. FERC*, 638 F.2d 388, 401 (2d Cir. 1980), *cert. denied sub nom. Penn Yan v. New York State Electric & Gas Corp.*, 454 U.S. 821 (1981); *Florida Power & Light Co. v. FERC*, 660 F.2d 668 (5th Cir. 1981) (same holding verbatim); *Richmond Power & Light*, *supra*, 574 F.2d at 619.

[43] 16 U.S.C. 824j, §824k.

The Commission does not appear to rely upon Sections 211 and 212 as authority for its transmission proposals. These sections are not mentioned in the Preamble or in the only reference to legal authority for the transmission proposals.[44/] Moreover, the Preamble explicitly indicates that the Commission is not holding an evidentiary hearing in this proceeding.[45/] Because Section 211 indicates that FERC may issue a transmission services order only "after affording an opportunity for an evidentiary hearing," this statement appears to conclusively establish that the Commission is not attempting to proceed under Sections 211 and 212 to implement changes to transmission services in this rulemaking.[46/]

Furthermore, none of the comments filed to date by advocates of conditional transmission services suggests that the Commission

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[44/] NOPR at 86, n.124.

[45/] NOPR at 96.

[46/] Since the Commission does not even attempt to satisfy this important prerequisite to reliance upon Sections 211 and 212, these comments will not address the numerous other reasons why those provisions cannot be relied upon as authority for implementing the transmission aspects of the proposal.

should rely upon Sections 211 and 212 as the source of authority for the changes that they seek. For these reasons, these comments will not address the numerous reasons why Sections 211 and 212 do not provide authority for mandatory conditional transmission services.

Nevertheless, Sections 211 and 212 are relevant to our general discussion of the scope of the Commission's authority because they demonstrate that when Congress chose to modify the prior absolute restriction on the Commission's authority to order transmission services, it did so expressly, it narrowly defined the circumstances for which and under which transmission services could be required, it expressly required that such order "reasonably preserve existing competitive relationships," and it continued its preference for voluntary transactions.

Sections 211 and 212 constitute an express grant of statutory authority. However, these provisions impose numerous detailed substantive and procedural requirements which limit the purposes for which and the circumstances under which transmission services could be mandated by the Commission. Findings under these provisions must assess the public interest and impacts on efficiency and reliability. The Commission must find that the order is not likely to cause the transmitting utility to suffer an uncompensated economic loss or other undue burden; will not unreasonably impair reliability or adequacy of service;[47] that the applicant for transmission services has demonstrated that it is ready, willing and able to pay the reasonable costs of transmission services plus a reasonable rate of return on such costs; and that the wheeling order would reasonably preserve existing competitive relationships. Section 212 explicitly restricts QFs from seeking transmission service orders under Section 211 while Section 211(c)(4) explicitly prohibits orders which provide for transmission of electricity directly to an ultimate consumer.[48]

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[47] The importance of reliability and the difficulties of (Footnote Continued)

These provisions show that Sections 211 and 212 were intended to "narrowly define" the purpose for which transmission services could be required and that competition was not one of those purposes. Congress never designed Sections 211 and 212 to alter the competitive environment, either to enhance or to hinder competition. The idea of maximizing competition has no place in the language of Sections 211 or 212, and is expressly rejected in their legislative history.

(Footnote Continued)
maintaining reliability in light of the unique nature of the transmission system, its interrelationship with electricity generation and other relevant factors are discussed in Appendix B.

[48] A separate type of transmission service authority in Section 211(b) applies primarily to one narrow circumstance which has no relevance to competitive bidding. Section 211(b) applies only to a resale customer whose supplying utility refuses to sell power to him, and who has no alternative but to seek transmission of power from some other source. See City of Manti, Utah, v. Utah Power and Light Co., 30 FERC Par. 61,229 (1985) at 61,457 n.10.

The Commission itself conclusively determined that it lacks the statutory authority to order mandatory wheeling to promote competition in Southeastern Power Administration v. Kentucky Utilities Company.[49] After examining the language of Sections 211 and 212 in light of PURPA's Congressional intent, the Commission stated that "we are not to order wheeling that significantly alters the competitive relationships among utilities in competition with one another for the same wholesale customers or the same retail customers."[50]

The analysis of these requirements in New York State Electric & Gas v. FERC, emphasizes the Congress' reluctance to disturb voluntary relationships. It concludes:

> [E]ven when all the prerequisites for the issuance of an order compelling wheeling have been met, the Commission is instructed to issue a proposed order, so as to allow the parties themselves an opportunity to agree on terms and conditions....
>
> These requirements reflect an intent to safeguard the voluntariness of wheeling arrangements to the greatest extent possible while providing 'assurance to all persons that they will be treated fairly and compensated fully' if they are compelled to provide involuntary services.[51]

These requirements and their legislative history demonstrate that Congress was aware of the prior restrictions on the Commission's authority to mandate transmission services.

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[49] Opinion No. 198, 25 FERC Par. 61,204 (1983), and Opinion No. 198-A, 26 FERC Par. 61,127 (1984).

[50] 25 FERC at Par. 61,533.

[51] 638 F.2d at 402. (emphasis in original).

This is borne out by the Senate Report on the 1977 version of PURPA. The sole mention of transmission occurs as follows:

> Utility interconnections and power pools make possible economies of scale, reduction of aggregate capacity requirements, and sharing of power during emergencies. Expansion of interconnections and achievement of maximum efficiency from pools are primarily the responsibility of the utility sector, which has been active in this area.
>
> The federal government will follow closely the further progress of the utility sector. A proposed amendment to the Federal Power Act would remove a major gap in the authority of the Federal Power Commission by authorizing it to require interconnections between utilities even if they are not presently under FPC jurisdiction. The FPC would also be authorized to require wheeling the transmission of power between two non-contiguous utilities across another utility's system.[52]

As the last sentence shows, Congress was well aware that the Commission was not previously authorized to mandate transmission services.

Congress' concern about the need to impose limits on the Commission's authority to mandate transmission services and its desire to preserve existing competitive relationships and voluntary transactions is obvious from the complexity of and number of conditions imposed by Sections 211 and 212. One can only conclude that a Congress which "narrowly defined" the purposes for which and the conditions under which transmission services could be required did not intend to otherwise allow the Commission to mandate transmission services.

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[52] S. Rep. No. 95-442, Public Utility Regulatory Policies Act of 1977, 95th Cong., 2d Sess. (Sept. 20, 1977).

3. Competitive Bidding Does Not Result In Discriminatory Or Anti-Competitive Consequences Which Could Justify Mandatory Transmission As A Remedy.

Despite the clear prohibition on FERC mandating transmission services to promote competition, the NOPR notes that some contend that FERC can and must mandate transmission services as a condition of an electric utility's participation in the proposed "competitive bidding" programs.[53] These parties claim that competitive bidding would be unduly discriminatory and anti-competitive without mandatory transmission services. Such claims have no merit at all.

(a) There Has Been No Showing of Discrimination

Close analysis of these assertions reflect improper use of the term "discrimination," in several important respects. First, it is important to recognize that the purchase of power at avoided cost and the use of a competitive market to determine avoided cost is not discriminatory. The Supreme Court decision which affirmed the Commission's adoption of the full avoided-cost rule to implement PURPA stated that "the full avoided-cost rule plainly satisfies the nondiscrimination requirement...."[54] The Preamble correctly finds that the primary purpose of competitive bidding is to establish an alternative means of determining avoided cost and promote equitable rates for consumers and efficient use of facilities and resources.[55] It states that a properly implemented bidding procedure does not discriminate against QFs[56] or increase utilities' market power.[57] It correctly concludes that a bidding system can accomplish these objectives without altering the status quo with regard to QF's access to transmission services[58]

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[53] NOPR at 81.

[54] API, supra, 461 U.S. at 413.

Second, claims of "discrimination" when a utility provides no transmission service at all (as opposed to claims that it offers transmission to some and not to others) reflect improper use of the term "discrimination." The failure to offer transmission services at all is not discrimination and provides no basis for inclusion of mandatory transmission requirements to remedy such "discrimination."

A traditional and fundamental element of utility regulation is that the utility may not unduly discriminate in its rates, charges, and services. This policy is reflected in Sections 205 and 206 of the FPA, as well as Section 210 of PURPA. Section 205(b) prohibits an electric utility from granting any person an undue preference or subjecting any person to an undue disadvantage or maintaining any unreasonable difference in rates, charges, or services in any sale or transmission subject to the

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[55] NOPR at 13-16; 20-23; 81.

[56] NOPR at 23-24.

[57] NOPR at 82.

[58] NOPR at 81-82.

Commission's jurisdiction. Section 206(a) allows the Commission to review sales and transmission services subject to the Commission's jurisdiction for undue discrimination, and, if found, to determine a just and reasonable rate, charge, classification, rule, regulation, practice or contract and to impose that on the utility. The purpose of the anti-discrimination provisions is to ensure that similarly situated persons are treated in a "substantially similar" manner.[59] The refusal to offer transmission services to any one is not an instance of treating similarly situated parties in a dissimilar manner.

It has been asserted that the purchasing utility which uses its transmission system to acquire a competitively priced resource "discriminates" against an "unsuccessful" generator within its service area unless it offers its transmission system for use by the "unsuccessful" generator to reach other markets.[60] The provision of transmission service to QFs or other generators attempting to "wheel out" of the service area of a utility purchasing competitively priced power simply is not a substantially similar service to the use of that utility's transmission system to acquire power for service to its customers. This situation does not invoke the principles of the FPA dealing with discriminatory treatment.

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[59] St. Michael's Utilities Commission v. Federal Power Commission, 377 F.2d 912, 915 (4th Cir. 1967).

[60] SAB Memo at 4-5.

The March 8, 1988 memorandum from ELCON and CEPA expresses a different view than the SAB Memo, for it acknowledges that bidding limited to QFs requires no conditions for "wheeling out" transmission services.[61] However, the ELCON/CEPA Memo indicates that the inclusion of non-QF bidders would violate PURPA's mandatory purchase requirement whenever a QF lost to a non-QF bidder and thereby requires "wheeling out."[62] The memo ignores the fact that Section 210(b) of PURPA provides that the rules adopted by the Commission shall not impose a rate "which exceeds the incremental cost to the electric utility of alternative electric energy." The reason the utility would have no obligation to purchase capacity from the QF who 'loses' a bid to a non-QF is that the QF's price for the capacity exceeds the utility's avoided cost from the non-QF bidder. Moreover, the FERC proposal provides QFs a preference in case of a tie and requires a utility to purchase energy from QFs which lose a bid to supply capacity. Thus, even if a QF 'lost' to a non-QF bidder, it retains the benefits of PURPA and would be in no worse situation than if avoided cost were determined administratively.

Those advocating "wheeling in" appear to fear that a utility may use its own transmission system as an integral part of its proposed competitive sale to another utility with which it is interconnected, but will refuse to permit another entity to also use that system. Again, the example fails to fall within the "substantially similar" test that underlies the anti-discriminatory rules of the FPA. The integrated sale and delivery of electric energy by a utility is physically and economically different from the devotion of the utility's transmission system to the delivery of power on behalf of another generator.

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[61] ELCON/CEPA Memo at 1.

[62] ELCON/CEPA Memo at 7.

In short, the proponents of mandatory conditional transmission fail to point to a potential, let alone actual, discrimination of a kind prohibited by PURPA or the FPA. Thus, as the Preamble has properly concluded, the suggestion that such activities "may" take place "cannot be presumed in advance."[63]

(b) The Use Of Competitive Bidding To Determine a Utility's Avoided Cost Is Not Anti-Competitive

ELCON and CEPA also suggest that all-source competitive bidding would be anti-competitive if not accompanied by "wheeling-out" for QFs because inclusion of additional bidders exacerbates the purchasing utility's monopsony power and failure to provide an alternative outlet for QF capacity will result in bids below true avoided costs.[64] Their arguments are a blatant attempt to rewrite PURPA.

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[63] NOPR at 86.

[64] ELCON/CEPA Memo at 10-13. This argument appears to take a far more restrictive position than ELCON's September 23, 1987, memorandum to the Commission staff which sought wheeling for unsuccessful IPP bidders as well.

They claim that the true avoided cost level must be determined with reference to a number of different buyers. However, PURPA does not define the avoided cost ceiling with reference to area-wide or regional avoided costs, but with reference to the "incremental cost to the electric utility." This language mandates that the avoided cost ceiling be determined with reference to the costs of power available to each individual utility and clearly contemplates a focus on a single utility buyer. As the Preamble has concluded, the all source bidding situation, which these commentors complain establishes "monopsony power," is merely a means to determine each utility's true avoided cost. Moreover, as previously indicated, PURPA responded to the concern for utility monopsony power by imposing the mandatory purchase obligation, not by imposing a mandatory "wheeling out" obligation. The most anti-competitive result of all would be to combine the mandatory purchase obligation with a mandatory "wheeling out" condition.

4. The Commission Cannot Require Transmission Service To Remedy Anti-Competitive Or Discriminatory Practices.

Even assuming, however, that the utility participating in competitive bidding may be found in the future to violate the anti-discrimination provision of the FPA, or to engage in anti-competitive acts, such a finding would not authorize FERC to mandate transmission services.

The Commission may not exceed the limits on its jurisdiction in forming a remedy for discriminatory or anti-competitive practices. In Federal Power Commission v. Conway Corp.,[65] the Supreme Court indicated that the Commission could not remedy discriminatory or anti-competitive rates by prescribing the utility's retail rates because establishing retail rates is a remedy that is not within the Commission's power or jurisdiction. The Court stated:

> The Commission has no power to prescribe the rates for retail sales of power companies. Nor, accordingly, would it have the power to remedy an alleged discriminatory or anti-competitive relationship between wholesale and retail rates by ordering the company to increase its retail rates.[66]

Conway makes clear that the Commission may not issue an unauthorized mandate as a remedy to cure discriminatory or anti-competitive conduct.

Numerous court decisions agree that, because the Commission has no authority to mandate transmission services under the original Federal Power Act, the Commission may not impose transmission services to remedy findings of undue discrimination. Perhaps the most significant evidence of the Commission's lack of authority to mandate transmission services is the Richmond Power & Light decision, previously discussed, which explicitly rejects the Commission's suggestion that its discretionary authority allows it to mandate transmission.

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[65] 426 U.S. 271 (1976).

[66] 426 U.S. at 276-77.

Florida Power and Light Co. v. FERC[67] reached the same result. There, the court addressed the Commission's authority to mandate transmission services to remedy discrimination under Sections 205 and 206 of the FPA. The Commission ordered Florida Power and Light Company to file a tariff which incorporated a policy statement setting forth the circumstances under which the utility would offer transmission services. The Commission argued that the policy statement was a practice. The utility contended that the inclusion of the policy statement would force it to provide transmission services on the conditions set out and was, in effect, mandatory transmission. The court agreed with the utility and reversed the Commission's order. The court stated:

> While the Commission may not compel the transmission of electricity, it does possess the authority to review transmission contracts under §206(a) and to make modifications of those contracts upon a determination that the terms of such a contract are unjust, unreasonable, unduly discriminatory, or preferential (citations omitted). It also has the authority to review any change in such a contract under §205. In performing these functions with respect to a wheeling contract, though, the Commission must be especially careful not to overstep its authority and require the involuntary wheeling of electricity, absent compliance with the new §211 and §212 of the FPA.[68]

The Fifth Circuit clearly rejected the Commission's authority to mandate transmission as a remedy for undue discrimination, unless such an order was within the Commission's jurisdiction pursuant to Sections 211 and 212 of the FPA. The court recognized in a footnote that if parties believed Florida Power and Light discriminated in offering transmission services, the appropriate recourse was through an antitrust action, not a Commission-imposed remedy.[69]

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[67] 660 F.2d 668 (5th Cir. Unit B 1981).

[68] Id. at 673.

Further support for the proposition that the Commission may not mandate transmission under Sections 205 and 206 is found in New York State Electric and Gas Corp. v. FERC.[70] The Commission ordered the deletion from a transmission contract of a prohibition on a city selling wheeled electricity outside city limits. Although the Commission contended that the removal of the prohibition was not the equivalent of mandatory transmission, the court found that the effect of the Commission's order would be to increase the utility's obligation to transmit electricity over the amount it voluntarily agreed to transmit. The court decided that Sections 211 and 212 of the FPA must be complied with in situations where the Commission seeks to expand a voluntary commitment to transmit.[71] The court went on to state that the Commission may review and modify a transmission contract if a violation of Section 206 is discovered, however if the modification amounts to an order requiring transmission services, the provisions of Sections 211 and 212 must be met.[72]

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[69] Id. at 676, n.20.

[70] 638 F.2d 388.

[71] Id. at 401.

[72] Id. at 403.

Some proponents of conditional transmission services cite Central Iowa Power Coop. v. FERC,[73] as support for the proposition that the Commission may mandate such services to remedy undue discrimination. That interpretation of Central Iowa is over-broad and misleading. Although the court affirmed the Commission's finding that the basis for division of power pool participants into the two classes was discriminatory, the court rejected the argument that the Commission had the authority to mandate transmission services by pool participants to non-generating electric systems, a class clearly not similarly situated as the pool participants. In rejecting mandatory transmission services, the District of Columbia court relied upon the Otter Tail and Richmond Power and Light decisions and concluded that "arguments advocating mandatory wheeling in lieu of relying on voluntary wheeling should be addressed to Congress."[74] The Commission is not allowed to find undue discrimination under Section 206 merely because a more comprehensive plan might better achieve the goals of interconnection and coordination.[75] Similarly, the Commission does not have the authority to mandate transmission to make a bidding proposal more competitive. To do so ignores the clear intent of Congress that transmission, except in the limited circumstances governed by Sections 211 and 212, should be a voluntary decision of each utility.

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[73] 606 F.2d 1156 (D.C. Cir. 1979).

[74] Id. at 1169.

[75] Id. at 1168.

Associated Gas Distributors v. FERC[76] provides no authority to mandate transmission services in order to remedy undue discrimination. The authority of the Commission deriving from the Natural Gas Act cannot be applied in haec verba to situations involving proposed transmission services under the Federal Power Act; Congress has recognized that the natural gas industry is not identical to the electric power industry, particularly in the area of transmission, and has enacted significantly different statutes.

In Associated Gas, the pipelines attempted to challenge Order No. 436 by analogizing precedent involving anti-discriminatory provisions of the FPA to the Natural Gas Act. However, the Associated Gas court recognized that the legislative history of the FPA and NGA on this point are "materially different." It found:

> In its deliberations on the bill that ultimately emerged as the Federal Power Act, Congress considered and rejected a provision that would have "empowered the Federal Power Commission to order wheeling if it found such action to be 'necessary or desirable' in the public interest."[77]

The court's subsequent discussion of Richmond Power and Light v. FERC and Florida Power and Light v. FERC, including its observation that neither case "comes anywhere near stating the

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[76] 824 F.2d 981 (D.C. Cir. 1987).

[77] Id. at 998.

the Commission is barred from imposing an open-access condition in all circumstances,"[78] is overly broad, as may occur when an issue has not been fully briefed on the facts before the court because they were not central to the case. As indicated above, both cases expressly state that the Commission may not impose mandatory transmission services to remedy antitrust violations.

Moreover, even though some similarities exist between the Natural Gas Act and the Federal Power Act, Congress created very different regulatory schemes for gas and electricity, particularly with respect to transportation/transmission. For instance, Congress granted the Commission extensive certification authority over natural gas pipelines, but vested the Commission with very minimal certification authority for electric transmission lines. Except for lines subject to certain federal authority which cross international borders, lines that are directly associated with FERC licensed hydroelectric projects, or lines which are subject to federal permits or certification, most transmission lines are "certified" at the state level.

Second, the organization, structure, regulation, and marketing relationships of the natural gas industry differ fundamentally from the electric industry. Natural gas fields are often located far from demand centers, so transportation is essential. This is not necessarily true for electric generation. Electric producers have the option to ship fuel to generation sites near load centers, rather than to transmit electricity long distances. In addition, unlike natural gas, which can be stored until it is needed, electricity cannot generally be stored in any meaningful amounts. Electricity must be produced and delivered to the customer by the power supply system at the instant the customer demands it. As a result, electrical transmission systems are built to accommodate an immediately anticipated demand for electricity. Gas transmission, on the other hand, is not so closely related to immediate demand.

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[78] *Id.* at 999.

The technical transmission of gas is very different from the transmission of electricity. Natural gas may be channeled with virtual certainty through specific pipelines at specific times. Electricity does not flow in alternating current lines (the predominant form of transmission) from point to point over directed paths, like natural gas, but instead selects the path of least resistance, often resulting in circuitous and unpredictable routes. As a result, the flows of electricity through transmission networks connecting generating sources to electricity loads cannot be precisely controlled or directed.

Finally, gas transmission companies are almost fully regulated at the federal level because of their clearly interstate nature. Electric utilities are regulated predominantly at the state level. This is a key distinction between gas industry regulation and that of electric utilities.

In response in part to perceived discrimination in the natural gas industry, in 1978 Congress passed the Natural Gas

Policy Act ("NGPA"),[79] deregulating gas at the wellhead. Congress' purpose in enacting the NGPA was to foster competition for natural gas, not (as was the case with PURPA) to encourage energy conservation. Congress determined that gas producers did not have a natural monopoly over the market for the sale of gas. Therefore, in order to encourage competition, Congress removed federal controls over market entry, market exit, and prices of new gas.

Congress did not make a similar finding with respect to gas transporters. Instead, federal controls were retained as Congress found that interstate pipelines exercised the same amount of control over the market that they did at the time of the enactment of the Natural Gas Act. Competition, therefore, could not be encouraged at the risk of reducing regulation.

In comparison, PURPA, which was passed contemporaneously with the NGPA, contained very different provisions. Section 210 of PURPA encouraged qualifying alternative energy producers but imposed a mandatory purchase obligation on utilities, not mandatory transmission. PURPA added Sections 211 and 212 of the FPA, which give FERC limited authority to mandate transmission services, but not in situations contemplated in this proposal.

The provisions of the Federal Power Act are clear. The Commission may review and modify any rate, schedule or agreement under its jurisdiction for undue discrimination under Sections

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[79] 15 U.S.C. Sec. 3301 et seq. (1985).

205 and 206 of the Act. However, the Commission may not order a remedy that is outside its authority. Until the addition of Sections 211 and 212, the Federal Power Act did not contemplate involuntary transmission services under any circumstances. With the addition of Sections 211 and 212 the Commission received very limited authority to mandate transmission, but these provisions cannot be applied and are not relied upon in this rulemaking. The only circumstances in which the Commission may order involuntary wheeling is when the requirements of Sections 211 and 212 authorizing the Commission to mandate wheeling have been satisfied.

C. The Commission Cannot Evade The Prohibition On Mandatory Transmission Services By Contending That It Is Just A "Condition" Of "Voluntary" Competitive Bidding.

Several parties have argued that the Commission can avoid the limitation of its authority, by claiming that the Commission is not really "requiring" anybody to provide transmission services. Instead, these parties argue, the Commission is simply making access a condition of the utility's voluntary decision to purchase supplies through competitive bidding or participate in its own or another utility's bidding solicitation. If the utility chooses not to conduct bidding or participate, it does not have to grant transmission access. Therefore, the argument concludes, the utility is not really being forced to provide transmission, and the Commission does not have to worry about its lack of authority to mandate transmission. That argument is wrong on both the facts and the law.

Under the proposal, the utility does not have the right to decide whether to conduct competitive bidding. The Commission's bidding proposal is voluntary for the state commissions, not for the utilities. Furthermore, if a state mandates bidding for non-QFs, a utility would have no realistic choice except to participate in bidding if it believes it can provide the needed service at the lowest reasonable cost. Thus, its decision to bid, as opposed to construct under traditional regulation, would not be voluntary. If the utility refrained from bidding, it would likely submit its anticipated plans to establish an avoided cost 'benchmark'. Such a benchmark might be unlikely to prevail against bidders if it were based on traditional cost-of-service concepts. However, if the utility "benchmark" were to prevail against bidders, would it be treated as a bidder and be compelled to provide "wheeling out"? There is no voluntary decision by the utility, so it is pointless to pretend that transmission can be made a condition of some "voluntary" act. If bidding is mandatory at the state level, a utility believes it has the best offer and access is a condition of bidding, then the utility must bid and access is mandatory.

The same would be true even if the state did not explicitly require bidding, but indirectly compelled a utility to purchase through bidding, i.e., any refusal to initiate bidding would be considered imprudent. In that case, the utility has no realistic choice at all. It could not realistically build its own plant knowing that the cost of such a plant would be disallowed as imprudent. Furthermore, a state that mandates bidding may well expect other utilities in the state to participate as bidders. Such a state could effectively compel a utility to bid to supply neighboring utilities by threatening to penalize the utility if it does not offer to sell to others. A utility could not realistically refrain from bidding in such a situation.

Even if the decision to bid to supply oneself or others is voluntary, FERC can not realistically presume that this reveals a voluntary decision to offer transmission services. We have shown in Part II above that both wheeling in (for successful bidders) and wheeling out (for unsuccessful bidders) would not necessarily increase either competition in the bidding process or efficiency, and in many cases would not even relate in any manner to bidding.

Under the proposal, there is absolutely no relation between the amount of capacity to be wheeled or the duration of the wheeling arrangement and the utility's bid. A utility could be forced to wheel far more capacity than it has included in its bid and for a far longer period of time. For example, a utility which bids to supply 100MW of capacity surely does not volunteer to provide transmission services for substantially greater amounts of capacity, but could be forced to do so under this proposal. Similarly, a utility which wins its bid to supply itself may have no transmission capacity to wheel out for losing bidders within its service territory, yet would be assumed to volunteer to provide such a service under this proposal.

Moreover, the proposal fails to recognize that there may be substantial differences between the bidding utility and the utility seeking wheeling with respect to the location of the generation facilities involved, the transmission path, the quality of power, the controls provided, and other operating and system impacts. Under the proposal, a utility could be forced to provide transmission services over paths it had never intended to affect, to disrupt its own and neighboring system's operations, to lose the opportunity for transactions to benefit its native customers and to face increased threats to reliability and adequacy of service. This is particularly true because, as we stated above, a utility required to wheel would have no means to exert control over these important factors. In comparison, a utility submitting a bid (and theoretically even a utility choosing to purchase from bidders) would have control over these factors. Thus, from the perspective of a bidding utility there is no relation between its decision to bid and its ability to wheel for others, let alone any element of voluntary offering of transmission services.

If FERC provides non-utility bidders advantages over utility bidders (as it has proposed to do in its definition and regulation of IPPs) and if it allows wholesale requirements customers to solicit bids, these problems would be further exacerbated. For example, if wholesale requirements customers solicit bids, utility requirements suppliers would have no realistic alternative to bidding, yet would be unable to compete on a level playing field, and would be treated as if they had "volunteered" to provide transmission services to winning bidders. These circumstance reveal that the conditional wheeling discussed in the proposal is not voluntary. Rather, FERC is imposing upon a utility a Hobson's choice: do not bid to supply electricity to wholesale requirements customers or else bid and face the need to wheel for others. There is no voluntary choice at all. "When a condemned man is given the choice between the noose and the firing squad, we do not ordinarily say that he has 'voluntarily' chosen to be hanged."[80] Clearly in this case, the utility is not taking any "voluntary" action.

The take-or-pay provisions of FERC's order in Associated Gas were actually reversed partly because FERC had attached a condition to an act which really was not voluntary at all.[81] The same result should happen in the present case. Once the facade of "voluntary" action is stripped away, it becomes clear that this proposal effectively forces the utility which wishes to bid to offer transmission services. The effect is the same as if the FERC had issued a generic order mandating transmission services without making findings under Sections 211 and 212. As indicated above, FERC cannot compel transmission services without complying with these requirements and FERC has not and cannot rely upon these requirements in this rulemaking.

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[80] Associated Gas Distributors v. FERC, 824 F.2d at 1024.

[81] Id. at 1024-25.

D. The Commission Cannot Give The States Authority To Mandate Transmission Services

Since the FERC has no authority to order transmission services as a pre-condition of bidding, it obviously cannot delegate any such power to the states. However, some parties may argue that, even if Sections 211 and 212 of the FPA require an evidentiary hearing and findings of fact, FERC may delegate its limited authority to the states, allow the states to hold the evidentiary hearings and let the states require wheeling. That argument is wrong on the law.

The Federal Power Act provides a comprehensive regulatory mechanism vesting the responsibility of regulating the interstate sale and transmission of electric energy exclusively in the FERC.[82] The Commission has discretion in the manner in which it exercises its regulatory powers, but it must regulate, and does not have the ability to refuse to exercise the powers required by statute.[83]

The Federal Power Act is founded upon a congressional intent "to draw a bright line easily ascertained between state and federal jurisdiction."[84] Moreover, the jurisdiction of the

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[82] 16 U.S.C. 824 et seq. (1985). See FPC v. Southern California Edison, 376 U.S. 205 (1965); see also Nantahala Power and Light Co. v. Thornburg, 106 S.Ct. 2349 (1986); New England Power Co. v. New Hampshire, 455 U.S. 331, 340 (1982).

[83] See FPC v. Texaco. Inc., 417 U.S. at 394.

[84] FPC v. Southern California Edison, supra, 376 U.S. at 215.

Commission over rates, terms and conditions is plenary, preempting all attempts by state commissions to assert direct or indirect control over jurisdictional rates or service.[85]

Once it is determined that transmission of electric energy is in interstate commerce and subject to federal jurisdiction, as nearly all non-QF power procured through bidding certainly will be, the Commission "has no discretion to reject that jurisdiction."[86] In addition, unlike the Natural Gas Act, the Federal Power Act does not authorize the Commission to defer to state regulators if the transaction is primarily local in nature. Given the pervasive and exclusive scope of the Commission's jurisdiction, and the absence of any specific grant of power to the Commission to delegate its obligations under the Federal Power Act, "the Commission's authority to set rates, terms and conditions of transmission arrangements is ... exclusive, nondelegable and may not be disclaimed."[87] This is true even if the transmission involves QFs under PURPA.[88]

Therefore, to the extent that FERC has some authority to compel transmission under Sections 211 and 212, it cannot delegate any of that authority to the states. If FERC wants to mandate conditional transmission, FERC itself must hold evidentiary hearings as to each affected utility, and FERC itself must make findings of fact under Sections 211 and 212. Any attempt to delegate that power to the states would constitute an unlawful delegation of federal authority, and therefore must be rejected as a matter of law.

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[85] Nantahala Power, 106 S.Ct. 2349, New England Power, 455 U.S. 331; Florida Power and Light, 40 FERC Par. 61,045.

[86] FPC v. Southern California Edison, 376 U.S. at 209 n. 5, quoting City of Colton v. Southern California Edison, 26 FPC 223, 236 (1962).

[87] Florida Power and Light, 40 FERC Par. 61,045 at 61,121 (July 20, 1987). (Emphasis added.)

[88] Id.

E. PURPA Offers No Legal Basis For Conditional Mandatory Transmission Services

Commissioner Stalon's concurrence states that "conditioned access would be a legal exercise of PURPA administration and implementation authority" and suggests that the source of such authority is Sections 210(f) or 210(a) of PURPA.[89] Although Commissioner Stalon states that the NOPR contains a legal analysis to support these conclusions, the legal analysis to which he refers[90] is not identified. The absence of any analysis in the NOPR regarding the legal basis for the transmission proposal raises a significant obstacle to our ability to comment effectively. Nevertheless, we have reviewed the applicable provisions of Section 210(f) and Section 210(a) of PURPA and conclude that they provide no basis for such authority. Section 210(f) of PURPA provides, with respect to states:

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[89] Stalon statement at 3 n.5.

[90] *Id.* at 5.

> (f) Implementation of Rules for Qualifying Cogeneration and Qualifying Small Power Production Facilities -
> (1) Beginning on or before the date one year after any rule is prescribed by the Commission under subsection (a) or revised under such subsection, each State regulatory authority shall, after notice and opportunity for public hearing, implement such rule (or revised rule) for each electric utility for which it has ratemaking authority.

In Federal Energy Regulatory Commission v. Mississippi,[91] the Supreme Court upheld the constitutionality of this provision based upon its view that the FERC rules offered the state commissions considerable latitude in implementation, including the opportunity to comply simply by adjudicating disputes arising under the statute. However, nothing in the plain language of Section 210(f), its legislative history or the Mississippi decision in any way suggests that the Section 210(f) authorizes State commissions to do anything to mandate transmission services. They are simply directed to implement Commission rules applying Section 210(a) of PURPA.

Section 210(a) of PURPA also provides the Commission no authority to mandate transmission services directly or indirectly. Section 210(a) of PURPA directs the Commission to promulgate:

> such rules as it determines necessary to encourage cogeneration and small power production which rules require electric utilities to-
> (1) sell electric energy to [QFs] and
> (2) purchase electric energy from such facilities.

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[91] 456 U.S. 742, 759-760 (1982), reh. denied, 458 U.S. 1131 (1982).

Section 210(c) establishes the scope of the rules for sales by utilities to QFs while Section 210(b) establishes the scope of rates for purchases by utilities from QFs.

As discussed above, Richmond Power & Light[92] expressly rejected the claim that the Commission's authority "to impose requirements and conditions 'necessary or appropriate to promote the policies'" of the FPA allowed it to impose transmission requirements. The court held that "such conditions may not contravene the Act" because "what the Commission is prohibited from doing directly, it may not achieve by indirection."[93] PURPA provides no basis for any contrary result.

In API v. American Electric Power Service Corp.,[94] the Supreme Court interpreted Section 210(a) as granting "the authority to promulgate such rules as are necessary to require purchases and sales..." (emphasis added). This statement recognizes that Section 210(a) does not vest the Commission with unlimited authority to implement all actions that may encourage QF development, but limits the scope of Commission rules to those which are necessary to require purchases and sales involving QFs and to establish rates for such transactions. In API the Court recognized that this authority encompassed interconnection rules because "[n]o purchase or sale can be completed without an interconnection between the buyer and seller."[95/]

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[92] 574 F.2d at 620.

[93] Id.

[94] 461 U.S. at 418.

This rationale does not apply to the type of mandatory transmission services discussed in the proposal. Experience under the Commission's current rules demonstrates that mandatory transmission is not necessary to complete purchases or sales with QFs. In fact, QF development under existing rules has exceeded all expectations. Further, as we have shown above, adoption of all-source competitive bidding merely modifies the procedures used to determine avoided cost. While all-source bidding may result in a more accurate determination of avoided cost, it does not permit a utility to evade selling electricity to a QF or restrict purchases from QFs that are consistent with the avoided cost standard.

Even if the scope of the Commission's discretionary authority under Section 210(a) to promulgate rules is more expansive, it cannot be read to repeal the long-standing interpretation confirmed in Otter Tail that the Federal Power Act precludes the Commission from mandating transmission services. The Commission has admitted that the provisions of the FPA and PURPA are "inextricably intertwined," and that the Conference Report to PURPA "shows that the Committee did not draw fine distinctions between PURPA and the Power Act."[96/]

[95/] Id.

[96/] Reply Brief for the Federal Energy Regulatory Commission
(Footnote Continued)

Even if PURPA is considered completely separate legislation, new legislation is presumed to be consistent with existing precedent unless Congress clearly manifests a contrary intent. The D.C. Circuit has recently stated:

> it has become a "contemporary precept that Congress legislates on the basis of policies and principles it has followed in the past, and unless Congress makes an express statement in the legislative history that it has abandoned long-standing precedent, the court will presume its retention."[97]

Similarly, in Johnson v. First National Bank of Montevideo, Minn., the court stated:

> If we assume, as it is proper to do, that Congress acts with knowledge of existing law, Cannon v. University of Chicago, 441 U.S. 677, 697-98...(1979), it follows that absent a clear manifestation of contrary intent, a newly-enacted or revised statue is presumed to be harmonious with existing law and statutes and its judicial construction.[98]

As we have shown above, Congress was clearly aware that the Federal Power Act did not permit the Commission to order transmission services. It adopted Sections 211 and 212 of the Federal Power Act to grant the Commission the authority to mandate transmission services in precisely defined circumstances. In comparison, the language and legislative history of Section 210 of PURPA reveal no intent, let alone a clear or express

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(Footnote Continued)
in API v. AEP Service Corp. (S.Ct. No.82-34, March 1983) at 12 n.12.

[97] National Treasury Employees Union v. MSPB, 743 F.2d 895, 916 (D.C. Cir. 1984), citing an article by Judge Wald.

[98] 719 F.2d. 270, 277 (8th Cir. 1983).

intent, to permit the Commission to mandate transmission services, either directly or indirectly.

Particularly in this situation, where Congress was obviously aware of the restrictions on the Commission's authority to mandate wheeling and adopted express language to modify that restriction in other limited circumstances, it is inconceivable that Congress intended Sections 210(a) or 210(f) of PURPA to have the sweeping effect that Commission Stalon appears to suggest.

APPENDIX B

COMPETITIVE BIDDING, NON-UTILITY GENERATORS, AND POWER SUPPLY RELIABILITY

APPENDIX B

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I. INTRODUCTION

The purpose of this Appendix is to assess some of the potential impacts of FERC's competitive bidding and IPP proposals on reliability. Many participants in the debate over power supply policy have framed the reliability question in terms of comparing the operation of non-utility plants to plants built by utilities. Although EEI does believe that, because a non-utility generator might have fewer backup systems to ensure reliable plant operation than a utility normally provides, a non-utility plant might be less reliable than a utility plant, our larger concern is over the impact a proliferation of non-utility generators would have on long-term system planning and day-to-day system operation.

Therefore, this Appendix focuses on the reliability impacts that would result from the achievement of FERC's goal of "introduc[ing] more sources and greater competition for supplying new capacity needs...."[1] If FERC's proposals succeed in changing many of the traditional ways that electric utilities procure their generating needs, there could be serious repercussions on the system planning and operating procedures utilities have so successfully followed to provide a reliable power supply system. These changes could dramatically increase the uncertainty of who will generate the power, where generating plants will be located, when the new generation facilities will come on-line, and the impact that a proliferation of non-utility generation will have on the existing system. For example, bidding programs that are open to non-QFs and mandated by states, rather than voluntarily undertaken by utilities, could undermine a utility's flexibility over supply options and its control over non-price factors. For these and other reasons, the achievement of FERC's goals in the competitive bidding and IPP NOPRs of inducing more competition for power supply could have a significant impact on the utility's ability to plan for an expansion of generation and transmission, with serious implications for reliability in the future.

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[1] Draft Environmental Impact Statement at 2-8. The use of competitive bidding only among QFs involves somewhat different considerations with respect to system planning issues because in many states a formal bidding system may actually improve a utility's ability to plan for the use of QF capacity. However, the proliferation of QFs continues to pose problems with respect to system planning and operational issues.

In the short term, if FERC's proposals lead to increased competition and reliance on non-utility generation, this could impair economic dispatch, affect response to emergency circumstances, and disturb existing arrangements for coordinating outages, plant scheduling, spinning reserves, and data acquisition. For these and other reasons, implementation of FERC's proposals could adversely impact the procedures that have worked so well to maintain reliability of the day-to-day operation of an interconnected grid.

This Appendix addresses some of these planning and operational issues FERC needs to consider before implementing changes to power supply regulation. It describes the unique characteristics of electricity and the planning and operational procedures utilities have developed in light of these properties. It then examines the implications that FERC's proposals could have on those procedures and addresses the reliability issues addressed in the Draft Environmental Impact Statement (DEIS) issued by FERC in connection with the IPP and Competitive Bidding NOPRs on June 16, 1988.

II. THE RELIABILITY ACHIEVEMENTS OF THE ELECTRIC UTILITY INDUSTRY

One of the most compelling attributes of the current system of electric supply in the United States is its high degree of reliability. When someone turns the light switch "on," over 99.9 percent of the time the existing utility systems are able to provide the power instantaneously.[2] People, whether at home, in the office, or on the assembly line, depend upon this reliability, as does business and government. In fact, a great deal is at stake when reliability is jeopardized: reliable electric service is vital for our national security and economic well being. It is therefore critical that any proposals affecting power supply in this country need to be evaluated in terms of their impact on the reliability that is so valuable to the country as a whole.

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[2] Attachment to Testimony by William McCollam, Jr., Edison Electric institute, Before the United States House of Representatives, Energy and Power Subcommittee of the Energy and Commerce Committee, September 22, 1987, p.15.

Vertically integrated electric utilities are responsible for providing a substantial portion of the electricity sold in the United States. Utilities receive a retail franchise granting them the right to provide retail service in a particular area in exchange for the obligation to provide adequate and reliable power supply at the lowest reasonable cost to customers. To meet these obligations, electric utilities are responsible for ensuring that generation, transmission, and distribution capacity is sufficient, and generation and load remain in balance at all times.

Recognizing the benefits of working together, most vertically integrated utilities engage in coordination transactions by interconnecting their transmission systems to assure reliability of power supply and to achieve economies in system development and operation. In some cases, utilities have formed power pools to take advantage of formal coordination through centralized economic dispatch. In other cases, utilities coordinate operations through bilateral and multilateral agreements which sometimes require transmission services. Coordination, whether through formal pools or other agreements, produces many benefits for utilities and their customers, including improved system reliability, reduced capacity margin requirements, lower production costs, and a wider market for purchases and sales.

The unique characteristics of electricity complicate the task of providing reliable service. Electricity generally cannot be stored; it must be produced instantaneously upon demand.

Further, electricity, following the laws of physics, flows over the paths of least resistance, which may include all of the routes, however indirect, between two points. The high degree of interconnection of U.S. utilities within three interconnected networks, coupled with these fundamental properties of electricity, makes the provision of a reliable power supply a very complex task.

Utilities have met the challenge by establishing procedures among interconnected utilities for cooperation with respect to long-term planning and general day-to-day operations. If utilities fail to follow these procedures, reliability will be jeopardized. Any proposals that complicate the mechanisms for long-range planning and inter-system coordination of day-to-day operations could harm the reliability of the electric system on which our country has come to depend. It is critical that the potential costs and risks of regulatory changes affecting power supply procurement be carefully weighed against the potential benefits. Many trade-offs are involved.

However, because we are so accustomed to a highly reliable electric power supply system, we run the very real risk of taking it for granted when implementing changes to the way in which power is supplied. Before implementing any changes affecting the manner in which utilities procure power supplies, FERC needs to consider the impacts on reliability of such changes on the electric system.

III. CONSIDERATIONS FOR UTILITY SYSTEM PLANNING

When a utility plans its generation, transmission, and distribution needs for the future, it focuses on three distinct dimensions. First, it considers the need for and timing of new supply additions. Planning for a horizon anywhere from 10 to 30 years into the future, a utility considers various supply alternatives and chooses the one that has the lowest present value, consistent with necessary non-cost factors. The best alternative minimizes costs over the long term of the planning period, even if it leads to a higher expected cost in any given year.

Second, a utility examines the impacts of supply alternatives on its system as a whole. The optimum plan recognizes that a particular form of generation or particular transmission or distribution capacity addition needs to be compatible with the existing transmission, generation, and distribution system. The utility therefore needs to consider many factors such as fuel diversity, type of facility, (i.e., peaking vs. baseload), relation of generation sites to location of load and transmission lines, transmission limitations, the potential need for transmission enhancements, reliability considerations, impacts on utility system operations, environmental impacts, and other factors.

Finally, a utility has to consider the impacts of supply alternatives on the regional system with which it is interconnected. Due to the peculiar nature of electrical transmission, the best alternative from the viewpoint of an individual company may affect the reliability or economics of other utilities. Thus, interconnected utilities need to coordinate their planning.

Utility planning is complex. It requires a great deal of information exchange and coordination among many interconnected utilities. EEI is concerned that the FERC proposals will adversely affect system planning and increase uncertainty in each of the three planning dimensions. System planning might become more difficult for a number of reasons:

- The reliance on contracts with non-utility generators could increase the riskiness of supply alternatives and decrease flexibility to respond to changing conditions;
- Competitors could become reluctant to exchange sensitive information critical to the planning process;
- Utilities may lose flexibility in the selection of generation based on non-price factors; and
- Planning for transmission needs could become more difficult.

In the following sections, we discuss the possible ramifications of FERC's proposals for each of the issues above.

A. The Reliance On Contracts With Non-Utility Generators Could Increase The Riskiness Of Supply Alternatives And Decrease Flexibility To Respond To Changing Conditions.

Utilities currently have the flexibility to procure power from non-utility generators via contracts, or by building for themselves. If FERC imposes rigid regulations that encourage purchases over utility construction, the result could be both a decrease in available supply options and an increase in system complexity, uncertainty, and risk.

Under bidding, a utility will not know very far in advance who the supplier will be, what generation characteristics the suppliers will have, and where the supplier will be located. Bidding could make the timing of additions less predictable and the time frame for modifying the transmission network more uncertain, when compared to utility construction.[3] These uncertainties, when compared to the present environment of utility construction and when relatively few QFs are otherwise involved, will increase the difficulty of the planning process. They also could increase the risk that necessary events, such as the completion of plant on time, will not occur. This risk is not without cost: utilities may need to plan for greater reserve margins for generation and transmission resulting in higher costs to customers.

Another problem arises when a utility compares alternative supply options in the planning process. For timing purposes, a utility needs some assurance that alternatives will be available. There may be a greater risk that a non-utility supplier will not be able to live up to the terms of the contract than there is for a utility supplier. Also, terms and conditions of contracts with non-utility generators may introduce rigidities into the planning process, and thus reduce a utility's flexibility to adapt its plans to changing conditions. Further, such a supplier does not have service obligations and, therefore, will have a distinct advantage over a utility that does if a contract needs to be renegotiated. It may be very difficult for utilities to evaluate the viability of all non-utility suppliers or their projects for planning purposes. Once again, utilities will face increased uncertainty and potentially greater risks.

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[3] Transmission planning issues are discussed in more detail in Section III.D. below.

The possibility that the assumptions underlying a utility's plan do not materialize is another source of risk when procuring supply through contracts. Load forecasts change, as do external economic conditions and other factors. Also, interest rates and fuel costs can be volatile, dramatically affecting the costs of plants. Utilities often must adjust the timing of their supply plans when capital costs or demand forecasts change, sometimes during plant construction. If a utility secures its power supply through contracts, much of this flexibility could be lost. Furthermore, it is the utility and its customers who will bear the risk if changing external factors make a contracted-for supply source uneconomic.

If utilities contract for power from non-utility generators, uncertainties in load, capital costs, and fuel availability (including adequate stockpiles) would have to be dealt with in a manner different from traditional methods. While contracts could have contingency clauses for each of these possibilities, which would allocate some risks to the supplier, they might still result in the loss of flexibility and an increase in risk to the utility.[4] Electric utility experience in long-term fuel contracting and problems in the gas industry with take-or-pay contracts suggest there is the potential for prolonged litigation and other difficulties.

We discuss issues regarding long-term contracts further in Section V below.

B. Competitors Could Become Reluctant To Exchange Sensitive Information Critical To The Planning Process.

Utilities in an interconnected grid routinely exchange information necessary to develop long-term plans for the region. This information is necessary to analyze the operational and economic impacts of new facilities on existing generation and transmission facilities--all critical for the maintenance of reliability.

The capacity expansion planning process for a power pool member is a case in point. Whenever a utility in a pool decides to add capacity, pool-wide studies, which include production cost, short-circuit, transmission line load, and transmission system stability analyses, must be conducted. To complete such studies, each member of a pool needs to exchange information including peak load and energy forecasts, planned generating additions and estimated service dates, planned transmission additions, projected fuel costs, generator unit heat and forced outage rates, maintenance schedules, projected operation and maintenance costs, projected unit retirements, transmission line ratings and rating revisions, and projected future costs of money and fixed charges.

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[4] This issue of risk allocation is discussed in more detail in EEI's comments in Docket No. RM88-4-000, NOPR on Independent Power Producers.

In its report entitled Reliability Considerations For Integrating Non-Utility Generating Facilities With The Bulk Electric System, the North American Reliability Council (NERC) identified these and other information needs from non-utility generators in more detail and specificity. Presently, utilities exchange these information needs among one another voluntarily. However, if FERC's proposals put utilities in direct competition with one another, utilities may be reluctant, because of a lack of experience or competitive or antitrust considerations, to continue providing such information. This reluctance would harm the pool's ability to cooperate effectively.

The problem of information sharing becomes most acute when a large number of non-utility generators enter the picture. Lacking experience in the industry, they might be unwilling or unable to provide all of the data (which in some cases may be proprietary) needed to assess the regional impact of expansion plans. Also, the proliferation of non-utility generators may make information exchange more difficult. If potential generators fail to identify planned units, regional planning activities will obviously be stymied. This could result in a less reliable electric system or significantly increased costs to provide offsetting reserves in the generation and transmission systems. Even if potential generators were to identify potential generation plans, uncertainty as to which plans would actually be implemented would increase as the number of potential generators increases.

C. Utilities May Lose Flexibility In The Selection Of Generation Based On Non-Price Factors.

Criteria related to reliability are critical to the planning process, affecting both the utility's own system and the interconnected network. Examples of these factors include: (1) the availability, type, and cost of fuel; (2) financial viability of the project; (3) timing of the supply; (4) location of facility; (5) methods for facility start-up; (6) dispatchability of power; (7) expertise and experience of operator; (8) technology used; and many others.

Unless a utility demands strict satisfaction of all non-price factors for a bid to be accepted, suppliers will likely offer different combinations of price and non-price factors. A utility could also be restricted from negotiating with bidding participants on appropriate non-price factors.[5]

Most non-price factors are difficult to evaluate and compare among participants in a bidding solicitation. And aside from evaluating and comparing these factors, it may be difficult for a utility to select the appropriate combination of price and non-price factors in a bidding context, because there may be regulatory pressure for the utility to accept the lowest "priced" bid, regardless of non-price characteristics. Furthermore, selection of sources based on non-price characteristics may lead to allegations of favoritism in the selection process and increased exposure of the utility to litigation.

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[5] The NOPR suggests this on p.45: "When the bidding system is used as a means of acquiring additional capacity, some restrictions to satisfy the block of capacity that has been subject to the bidding process may be appropriate...."

D. Planning For Transmission Needs Could Become More Difficult.

FERC needs to be mindful of the impacts its proposals could have on the planning of transmission facilities, which, being the vital link between generation and customers, are essential to reliability. The location of new generating units directly affect the need for transmission line construction or modification, and utility planning procedures call for full coordination of generating plant siting and transmission system development. Competitive bidding could affect long-term transmission planning because it makes the eventual location and timing of generation more uncertain. Further, bidding increases the uncertainty of how many suppliers will be on the transmission system and how much capacity a utility will have to provide for third-party transmission services. All of these uncertainties may lead to a requirement for additional transmission reserve margins, thus resulting in increased customer rates. These potential cost increases are another source of trade-offs which must be examined against the potential benefits of bidding.

Under bidding, a utility might have three options in siting lines:

- Build redundant transmission capacity to enable the utility to meet a reasonable range of locations for generation with the system;
- Wait until the locations for the prospective generation capacity are known and then try to complete the transmission facilities in time to meet the system conditions that arise; or
- Incorporate geographical location into the bid criteria.

Under the first alternative, utilities would have to build a large amount of redundant transmission capacity to meet the uncertainties of future generation and customer locations. Of course, utility customers will have to pay for this unneeded reserve capacity and may object to the environmental and aesthetic grounds to "excess" transmission lines.

A utility following the second alternative runs the risk that the transmission capacity would not be in service when needed. It is doubtful that utilities could build new transmission facilities based on the two- or three-year lead times expected for non-utility generating units. Studies done by NERC show that the lead times for planning, siting, and construction of transmission lines range between three and ten years, with an average of five. While the bidding process could be structured to coordinate the timing of new generation with transmission capability, given recent difficulties in siting and certifying new lines, such coordinated timing could be very difficult to achieve.

A utility following the third alternative would be constrained to selecting bidders that may not offer the most economical or beneficial result with respect to other criteria.

The important point to consider with all of these alternatives is that transmission availability is heavily dependent on the entire generation, transmission, and distribution system and the effects of introducing new generation at different geographical and chronological points within that system. FERC needs to consider these issues in designing policies on bidding.

IV. CONSIDERATIONS FOR UTILITY OPERATION

Just as the FERC proposals could have negative ramifications on long-term system planning, they also could hamper operability and short-term operations planning. Utilities on an interconnected grid establish operating guidelines and procedures to ensure that power dispatch and control is efficient and the transmission network is adequate for reliability and emergency coordination. They coordinate maintenance scheduling, system studies, operating procedures in both normal and emergency conditions, and transmission operations in addition to exchanging information. These activities are critical for the maintenance of reliability.

Changes in policies affecting power supply procurement could adversely affect the inter-system coordination of operations for a number of reasons:

- Non-utility generators might not be willing or able to participate in inter- or intra-system incremental dispatch and coordination;

- FERC's proposals could hamper the ability of utilities to react quickly in emergency conditions;
- FERC's proposals could affect the ability of utilities to control and schedule operation for reliability;
- A proliferation of non-utility suppliers could adversely impact the coordination of unit commitment and maintenance schedules, system protection, data acquisition and monitoring, and provision of necessary spinning and operating reserves;
- A proliferation of non-utility suppliers could hamper the administrative procedures of power pools and coordination procedures; and
- A proliferation of non-utility suppliers could increase loop flows, creating opportunity costs to utilities and reducing levels of reliability.

Each of these concerns is addressed in the following sections of the paper.

A. Non-Utility Generators Might Not Be Willing Or Able To Participate In Inter- Or Intra-system Incremental Dispatch And Coordination.

In many cases, utilities operating in power pools or under coordination agreements minimize total production costs through centralized or coordinated dispatch of generation based on incremental production costs. For incremental dispatch to work, suppliers need to be willing to have their plants sit idle while cheaper capacity is used to meet the demand. Since the prospect of having idle capacity means uncertain revenues, non-utility generators might have difficulty receiving financial backing. Also, contractual obligations could undermine incremental dispatching and increase production costs if they force utilities to purchase non-utility capacity and energy that has a higher incremental cost than other alternatives at any point in time. Thus, again customers might face higher rates as a result of bidding, which might not be off-set by benefits from FERC's initiative.

A further problem arises if a non-utility generator markets its power to more than one utility located in two (or more) independent control areas. It is considerably more complex, difficult, and costly for one generator to be dispatched in two separate control area systems.

B. FERC's Proposals Could Hamper The Ability Of Utilities To React Quickly In Emergency Conditions.

Naturally, nothing threatens reliability more than emergencies--such as the downing of lines in an ice-storm, the malfunction of equipment, or an extended heat-wave causing a larger than anticipated surge in demand. In such situations, utilities strive to prevent widespread and prolonged system interruptions and to restore service rapidly in case of interruptions.

In support of these objectives, utilities have developed emergency operating guidelines, used by the operators of generating plants, substations, system dispatch centers, and distribution systems, to obtain a high level of reliability. Almost all power pool, formal, and informal coordination agreements have operating procedures for emergencies. These procedures are in the agreements and proceedings of the regional reliability council operating committees, and in other reliability council and NERC documents. The more organizations (and individuals) involved in a pool or coordination agreement, the more difficult it is to develop, coordinate and implement emergency procedures.

Emergency procedures depend on the ability and willingness of generation owners to increase or decrease their output, with the decision often being made through automatic controls to ensure rapid adjustment. Non-utility generators might be unwilling to cut back production of electricity or steam (in the case of cogeneration) for their own industrial needs or suffer other economic penalties resulting from an adherence to emergency procedures. They also might lack the experience needed to perform necessary operations. Thus, non-utility generators might be unwilling or unable to take the steps necessary to bring a system back "on-line" in an emergency.

C. FERC's Proposals Could Affect The Ability Of Utilities To Control And Schedule Operation For Reliability.

While utilities dispatch units based predominantly on incremental production cost, they must also consider system-wide reliability when scheduling generation. Rapid deviations from otherwise normal generating schedules are sometimes required in order to maintain proper system security and reliability. For example, if certain transmission lines trip out of service, then immediate changes in generation schedules may be necessary. This can be done if the generation is fully under the control of the electric utility. With non-utility ownership of generation, the utility's ability to adjust generating schedules could be hampered, even if such adjustment is guaranteed by contract.

In order to maintain proper frequency and voltage on a power system, generators are maintained under automatic control. The generating units and their controls are designed to make the proper response as loads on the systems vary from minute-to-minute and as system emergencies occur. Voltage is another key control factor, and utilities use voltage regulators and reactive dispatch techniques to maintain proper voltage to the customer. Non-utility generators will need to have their generation controlled in this manner. However, it may be hard to regulate the voltage of non-utility generators because the utility will have difficulty ensuring that the controls are maintained and kept in-service. Further, because of the economic penalties involved, non-utility generators may be reluctant to adhere to scheduling.

The NERC Operating Committee has specified procedures for testing the response of generation to control transmission tie line loadings and frequency.6/ The compliance of non-utility generators with these guidelines is critical because excessive flows over inter-utility tie-lines could cause trip-outs, with associated economic penalties. The economic consequences of not having proper voltage regulation would be severe in terms of its effects on the electronic equipment, motors and appliances of end-use customers.

6/North American Electric Reliability Council, Operating Manual, as updated, Princeton, New Jersey, March 1986.

D. A Proliferation Of Non-Utility Suppliers Could Impact Adversely The Coordination Of Unit Commitment And Maintenance Schedules, System Protection, Data Acquisition And Monitoring, And Provision Of Necessary Spinning And Operating Reserves.

NERC, in addition to the individual electric reliability councils, have established various reliability policies, criteria, and guides,[7] adherence to which is essential for the reliable operation of an interconnected system. These include coordination of unit scheduling, maintenance schedules, system protection devices that relieve system overloads before the system is damaged, data acquisition and monitoring, and spinning reserves necessary for meeting unanticipated demand.

This coordination will be increasingly difficult with an increased reliance on non-utility generators for a number of reasons. First, unit commitment scheduling must be done on a system basis by a central authority that assumes responsibility for that system. Non-utility generators might not be willing to comply with the central authority's decision if such compliance means the inability to produce power or steam for their own needs and/or loss of revenues. Second, maintenance scheduling will become more difficult with the addition of smaller generating units, particularly if utilities do not have control over maintenance schedules.

Third, the restoration of service in times of outages may require that certain facilities remain disconnected for extended periods while the system is "brought back." Non-utility generators may want to get back "on-line" sooner, and may not follow specified system restoration procedures. Fourth, spinning reserves benefit all customers and suppliers, but non-utility generators may view them as the utility's responsibility. For those who do not agree to help provide such reserves, the cost of ensuring spinning reserve requirements will fall on the utility and its customers.

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[7] North American Electric Reliability Council, Overview of Reliability Criteria, December 1982.

Finally, outages of certain components and auxiliaries (e.g., a feedwater pump) decreases the effective capacity of a unit. Non-utility generators may not always report such changes, impairing system reliability.

E. A Proliferation Of Non-Utility Suppliers Could Hamper The Administrative Procedures Of Power Pools And Coordination Transactions.

The coordinated operation of utilities requires administration, and FERC proposals leading to a proliferation of suppliers would make the administrative process more cumbersome and expensive. The complexity and costs of monitoring, record keeping, communication, automatic control, and emergency procedures will increase with a larger number of non-utility generators. This potential increase in administrative costs needs to be examined against the potential benefits of competitive supply options resulting from FERC's proposals.

The prospect of non-utility generators becoming members of power pools raises several issues that need to be resolved. For example, it is unclear what the voting rights of non-utility generators would be and what payments they would make towards the costs of overhead and facilities. Also, the basis for payments by non-utility generators, which could be different than that for utilities, would have to be determined as would the basis for determining capacity and energy payments in the event that individual non-utility generators were unable to meet contractual obligations. Finally, mechanisms would have to be established for the gathering of necessary data from non-utility generators.

F. A Proliferation Of Non-Utility Suppliers Could Increase Loop Flows, Creating Opportunity Costs To Utilities And Reducing Levels Of Reliability.

Transmission is the single most complicated aspect of maintaining reliable power supply. This is due to the aforementioned physical properties of electricity, namely, that if one utility sells power to another, the power does not necessarily flow over a direct or "contract" path between the two utilities. This characteristic is called inadvertent or "loop" flow, and utilities on an interconnected grid need to monitor all power from every source entering that grid to make sure that unintended power flows do not adversely impact the transmission system. Failure to do so could lead to an overloading of transmission lines and outages. In addition, loop flows reduce the capability of utilities to engage in cost-saving bulk power transactions for the benefit of their own customers.

For short-term transactions among electric utilities, loop flows do not cause severe economic or operational problems. Utilities rely on one another on a cooperative basis to deal with loop flow problems. If a particular power flow is threatening system operations, utilities that cause the problem or that can help to solve it will voluntarily adjust their generation.

However, the increase in the number of long-term, firm transactions, which could result from competitive bidding or a proliferation of non-utility generators, raises the prospect of a substantial increase in loop flow problems. Utilities that are not party to a power transaction, yet are affected by the inadvertent loop flow that results will face such flows over what could be twenty to thirty years. In addition to limiting other economic uses of transmission lines, inadvertent loop flows could cause a degradation to the affected utility's system reliability. Thus, because of loop flows, an increase in long-term, firm transactions could force a utility not party to the transactions to expand its transmission system completely at the expense of its customers.

Furthermore, since a utility affected by loop flow might not be a party to the transaction, or even within the same control area, there is no assurance than an affected utility could call upon non-utility generators to reduce their output to meet emergency conditions. Thus, the customers of affected utilities may bear the costs and risks of loop flows.

The loop flow problem is compounded by the lack of an easy solution. The NOPR does not suggest any means for compensating affected utilities who are not a party to a purchase transaction. But certainly, pricing alone will not solve the problem. Loop flow is a very complex technical and economic issue which regulators, to date, have addressed only in a few limited circumstances. A large increase in long-term, firm, power transactions is likely, however, to bring this issue to the forefront, perhaps before appropriate solutions are developed.

Finally, a proliferation of non-utility generators would increase the complexity and difficulty of monitoring power flows into or out of control areas. Such monitoring is critical to the main function of control areas--to keep generation in balance with load on a moment-to-moment basis.

V. A DISCUSSION OF THE RELIABILITY SECTIONS OF THE DRAFT ENVIRONMENTAL IMPACT STATEMENT

The Draft Environmental Impact Statement (DEIS) addresses reliability issues on pages 4-73 through 4-79. This section of this Appendix will address the arguments made and issues raised in the DEIS.

Pages 4-74 and 4-79 of the DEIS state that since bidding is voluntary and a utility would not be legally obligated to buy power from IPPs, a utility "would be free to negotiate terms of purchase that it finds acceptable."[8] Also, the DEIS lists several "checks and balances" contained in the NOPR that would protect reliability. However, as discussed below, these "checks and balances" may be illusory.

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[8] DEIS at 4-74.

The first such "check and balance" mentioned in the DEIS is the voluntariness of the implementation of bidding. However, the NOPR would make bidding voluntary on the part of the state and not the utility, and if utility experience with QFs is any indication, states may try to limit the utility's ability to negotiate non-price factors with IPPs. We discuss this voluntariness issue in greater detail in Sections II.B.1 and III.A.1 of our main comments.

The second "check and balance" referred to in the DEIS is that the NOPR does not require that all sources participate directly in the bidding. This may be true, but utilities would still need to consider excluded sources in an avoided-cost benchmark calculation, and it is not clear in the NOPR what role the benchmark would play if all bids exceed it; utilities might be required to purchase from the sources that comprise the benchmark in this case. Also, the NOPR leaves the decision of what sources to include in bidding to the state and not the utility.

The third purported "check and balance" is that "the proposed bidding rulemaking not only encourages, but actually requires, the explicit consideration of such factors as plant dispatchability, siting, and reliability in formulating the bidding program."[9] It is true that the NOPR calls for this, but it leaves open the possibility that state commissions may try to limit the utility's authority in this area. Also, the proposal recommends the development of numerical weights, which could make utility negotiation very difficult, and which would preclude utilities from making trade-offs between non-price factors. For example, a utility might identify a bid that is so superior with regard to one particular factor, that all other factors become less important. Numerical weights could preclude utility flexibility to take advantage of such a possibility. Finally, it is unclear that FERC would have the authority or ability to enforce the requirement that non-price factors be considered, or how such a requirement would be enforced by FERC.

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[9] DEIS at 4-75.

The final "check and balance" protecting reliability mentioned in the DEIS is the prudence process. The DEIS states: "[i]n the highly unlikely event that a bidding program produced an IPP winner that posed such a clear threat to system reliability that prudence would dictate not purchasing, the utility would have yet another forum to defend its actions."[10/] First of all, such an event is not "highly unlikely." Since the electrical system is so fragile, a bidding program that is not voluntary to the utility or in which the utility is not given flexibility to design and select the winner could produce an undesirable winner a majority of the time. Second, the DEIS appears to suggest that it would be prudent to reject suppliers that create a "clear threat" to system reliability. Given the

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[10/] DEIS at 4-75, emphasis added.

importance of reliability and the fragile nature of the system, this "clear threat" standard reveals far too great a willingness by FERC to accept risks to reliability. Finally, the DEIS also appears to suggest that prudence would be considered in a different proceeding than the one approving rates selected in a bidding program. Section II.B.3. of EEI's comments in this proceeding articulates why the prudence of a winning bid must be addressed in the rate approval process and why subsequent prudence challenges should not be allowed.

The DEIS also considers the implications on reliability relative to the fact that IPPs have no obligation to serve, other than that contained in a contract. The DEIS states, "[w]holesale trades are effectuated through contracts," and it then poses the question: "[I]f contracts are so unreliable, why have utilities embraced wholesale trading as a means of increasing system reliability?"11/ Yet the DEIS ignores the fact that most existing power contracts are for short-term economic or emergency coordination; the sort of transactions envisioned in the competitive bidding and IPP NOPRs, i.e., for long-term system adequacy and reliability purposes, are extremely rare in today's power market. Clearly, if such coordination transactions jeopardized reliability, they would neither be economic nor undertaken. It is for these very reasons that most power pool

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11/DEIS at 4-76.

-and coordination agreements contain specific requirements that utilities maintain sufficient capacity to meet their own needs.

The DEIS also points to the existence of "a number of joint-venture stand-alone" power plants and utility plants excluded from the ratebase that produce solely for the wholesale market without problems of reliability as evidence that IPPs would be reliable. While it is true that there are examples of both joint-venture, stand-alone plants and utility plants not in the rate base selling power only on the wholesale market, there are not many such plants. If the number joint-venture, stand-alone plants increases dramatically in a short time frame, the problem of integrating these plants into the utility grid may become more difficult. Also, utilities with a need to maintain system reliability operate or have an ownership interest in those existing plants and are willing and able to control them as necessitated by stability or voltage conditions.

The DEIS also addresses the issue of motivation. It notes:

> The IPPs, it is argued, are interested only in making profits. Clearly, investor-owned utility companies are also motivated by a desire for profits. The argument against IPPs seems to rest on a belief that utilities are motivated by something more than a desire for profits, that IPPs do not share this motivation, and that this motivation is essential for long-term, reliable operation.[12]

It is certainly true that investor-owned utilities would not exist were it not for the potential of making profits. However, utility profits are closely monitored by regulatory authorities,

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[12] DEIS at 4-76, emphasis added.

--who base a utility's allowed returns on the fulfillment of the obligation to provide adequate and reliable service at the lowest reasonable cost. A utility's profit therefore is inextricably linked to its service obligation, making that obligation a principle motivation of the utility.

The situation is very different for non-utility generators. This difference can be highlighted quite succinctly by reactions to an emergency: utilities share and coordinate in emergencies without respect to profits, but will an IPP be willing to do the same? Further, non-utility generators do not have that service obligation and their profits would not be regulated. While it might be possible for utilities to demand contract terms penalizing unreliable suppliers, such terms are likely to be resisted by suppliers in much the same way that QFs now complain that utility requirements for reliable interconnection facilities amount to "gold-plating." Such resistance may cause regulators to require, directly or indirectly, utilities to minimize such penalty clauses. In this situation, and without the obligation to serve, unregulated producers would have no penalty for risky operations that threaten system reliability. A utility and its customers would also be materially harmed if a non-utility supplier goes bankrupt and the plant, if on-line, is uneconomic. Finally, the utility's service obligation puts the utility at a disadvantage if a non-utility generator on which the utility has come to depend desires a renegotiation of contract terms. While it is true that the utility could sign a contract requiring up-front security or allowing the utility to take over a non-performing plant, neither option will help if the utility is relying on the capacity and the capacity is non-operable or non-economic. Thus, the argument that utilities with service obligations are more reliable than non-utility generators without such obligations--an argument to which the DEIS (see excerpt emphasized above) takes exception--is valid.

The DEIS also examines the obligation to serve issue from the perspective of take-or-pay contracts. The DEIS states, "A utility may negotiate a contract that calls for the IPP only to be paid for power that is actually produced. Such a contract provides tremendous motivation for reliability: you don't get paid if you don't perform."[13] However, many non-utility generators may require front-end loaded contracts to obtain financing. Such a generator could go bankrupt before supplying the power for which a utility had already paid. But perhaps more importantly, such contract terms would be inconsistent with the ability of the utility to dispatch or purchase from the supplier only when economic to the system. As noted earlier, if the non-utility generator's revenue stream is directly linked to its production, then there will be disincentives to the plant owner to operate the plant in a manner that always is consistent with the utility's reliability needs. Also, while utilities might not have to pay for power not produced, contracts, whatever their contingency clauses, might force utilities to pay for power that is uneconomic or not needed.

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[13] DEIS at 4-76 - 4-77.

Also relating to contracts, the DEIS indicates that a utility can stipulate terms and conditions under which it will purchase power from an IPP to maintain incremental dispatch and load following coordination arrangements. But this is true only if a non-utility generator can obtain financing in the situation of an uncertain revenue stream. There will be considerable pressure for the utility to provide an assured revenue stream to suppliers, as has been the case with QFs.

Finally, the DEIS discusses and refutes the notion that IPPs might be inclined to build substandard plants. We do not argue that they will, only that a utility provides substantial backup systems in plants, which increase the overall expense. It is questionable whether IPPs would be willing or have enough experience to incur similar expenses to provide the same level of plant reliability. In fact, unless the utility is able to require specific plant backup systems, cost competition in the bidding context is unlikely to produce bidders offering such back-up protection. And, if the utility does require specific back-up systems, they may be subject to charges of favoring particular technologies or bidders in the process.

The section on reliability in the DEIS conclusion that "...there appears to be no compelling reason to conclude that, as a class, IPPs will perform poorly."[14/] ignores the real issues. The primary issue is not that IPP plants individually or as a class may or may not be as reliable as utility plants, but that a large number of plants that might not be controlled by a utility are difficult to integrate into a highly complex power supply system without compromising reliability. These problems could be exacerbated by the involuntary nature of bidding on the utility as proposed in the NOPR, the differences in the motivations of IPPs as compared to utilities, and the over-reliance on contracts and power purchases to satisfy system reliability needs.

VI. CONCLUSIONS

Because the reliability of our electric supply is critical to our nation's economy and security, FERC needs to be mindful of the impacts of its proposals on reliability. FERC needs to be certain that the benefits from increased competition in power procurement are not offset by increased costs due to reduced reliability or increased risk and uncertainty.

System planning and operational issues need to be an important component of the evaluation of regulatory change affecting power supply procurement. Reliability is a critical issue which is really glossed over in the DEIS, without any real analysis, and then summarily dismissed in terms of potential

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[14/] DEIS at 4-79.

impact. The arguments in the DEIS, furthermore, are flawed. In addition to other reasons, they do not consider the impact of FERC's proposals on system planning and operations, and how those impacts in turn will affect reliability. These critical issues have not yet been addressed adequately by FERC, either in the competitive bidding and IPP proposals or in the Draft Environmental Impact Statement.

INDEPENDENT POWER PRODUCERS
AND
THEIR IMPACT ON UTILITY DEBT QUALITY

Remarks By

ROBERT W. BURKE

MOODY'S INVESTORS SERVICE

Before The

ENERGY DAILY'S ANNUAL UTILITY CONFERENCE

THE WATERGATE HOTEL

WASHINGTON, D.C.

NOVEMBER 2, 1989

I would like to direct my comments to independent power producers, particularly thinking about the non-utility producers, and what impact they could have on utility company debt quality. I will refer to the non-utility independent power producers as the "independents".

Today, many utilities are not as financially strong as they should be. Meanwhile, projections are being raised on expected sales, which could well bring the need for new capacity earlier than previously anticipated. Can we expect utilities to invest adequate capital now that certain important regulatory principles have been breached? The breakdown of the so-called "regulatory compact" with a variety of rate base and other terms of disallowance has convinced some managements never to build large plants again. Reliable service could be at stake. Others feel third parties can fill the gap. Here again, reliable service could be at stake. If financial risk increased with the breaking of the "regulatory compact" while utilities were providing reliable service--what would happen under conditions of unreliable service? If utilities are to be responsible for reliable service then they must be allowed the financial ability and the authority to succeed. In light of today's regulatory atmosphere, how will "capacity- short" and probably somewhat financially weakened utilities deal with beginning a new building cycle sooner than expected?

I would like to focus on a variation of the three "Rs" today -- regulation, risk and reliability.

Looking ahead, Moody's believes that regulatory plant disallowances and rate phase-in plans will not likely diminish in the future. New plants now awaiting rate base treatment and those few still under construction will undoubtedly be subject to such methodologies. Generally, there will be a brief respite from the challenge presented by new rate base additions because many companies currently are not building. However, when the pending round of construction is at hand, we expect that many utilities will avoid baseload construction for as long as possible and seek early regulatory approvals for any new plant investment they may undertake. The latter could be a reasonable approach to safeguard against so-called stranded assets.

As the day of reckoning in terms of power shortages approaches, third party non-utility independent power producers expect to build generating capacity to a much greater degree than in the past. Of course, they will need adequate terms on access to the existing transmission system. These IPP's, or "independents", will have an opportunity to demonstrate their value - or lack of it - in terms of their financial stability and reliability as a source of economical power. Sometime between now and the early to mid-1990's - the start of the next round of base-load construction - there may be an answer to the question of whether "independents" or existing regulated utilities will dominate future generating plant construction. But Moody's is not at all convinced that significant construction risks can be permanently shifted from the utility to an "independent".

Perhaps the traditional role of our investor owned electric utilities as basically self-sufficient entities deserves some further comment.

A regulated investor-owned utility has an obligation to provide electric service in its service territory. It must do this efficiently from a cost standpoint as well as from the standpoint of reliability. By and large, but not without recent serious concerns, the framework of the utility providing electric service under regulatory oversight has worked well. It has met the public need for relatively inexpensive and reliable electricity, while attracting investment capital on reasonable terms. However, we have some concern about diminished self-reliance. For example, there may be credit risk for the utility involved with long-term absolute take or pay contracts for purchasing electric power. Such contract obligations can justifiably be viewed as effectively increasing the purchasing electric utility's debt leverage and debt service requirements, if not offset by additional equity and/or other debt reduction. Moreover, the financial obligation represented by the contract will remain in place even if cheaper alternative power sources later become available. If the capacity of the "independent's" generating facilities are not reliable, the regulators might also establish restrictive plant performance guidelines and impose earnings penalties or disallow replacement power costs. At that point, regulators might be tempted to challenge the prudency of the utility in entering into the power contract in the first place. Contract expense disallowances which might lower credit quality--and Moody's ratings--are a potential consequence.

Moody's, however, also recognizes that power supply contracts, if properly structured and economical, may contain some advantages from a credit standpoint. The utility might be able to avoid the risks of some costly plant construction. If contracts contain explicit performance standards, and involve "independents" with a proven track record, and contract costs are appropriately reflected in rates, credit quality of the utility might not be impaired.

I should note at this point that Moody's analysts work to levelize the financial playing field, wherever possible, in order to more fairly compare the debt quaility of a universe of companies. This applies in the comparative evaluation of electric utility companies, which may contract for the purchase of power to a greater or lesser extent. One cannot ignore the debt implication in, for example, the purchase power contract between a highly leveraged "independent" and a utility company which maintains substantial equity in its capitalization. It is likely that the credit stature of the utility substantially supports, through the terms of the contract, the financing capability fo the "independent". Once this variance is accounted for by imputing an added debt and interest component to the company's financial statements, a more equal footing between it and other companies can be attained. After that, various other quantative and qualitative debt protection measures can be evaluated in the normal rating process. The degree of debt to be imputed is debatable. Many contracts are designed to place most all of the risk on the utility company. An absolute "take or pay" contract places the risk of both demand and operating performance on the purchasing party. Such a contract would call for the fullest imputation of debt under whatever method is employed. On the other hand, an absolute "take and pay" contract requires the seller to bear operational and demand risk. The imputation, of debt relative to this contract may be moderate or non-existant. Moody's approach is to evaluate each contract on its own merits and respond accordingly. An absolute take or pay obligation may be treated comparable to a general obligation of the purchasing company. However, if there are mitigating terms in the contract, such as the power seller assuming the risk of operating performance, a more moderate adjustment may be used. I must caution you, however, that these are only general guidelines. The many variations in terms and circumstances preclude a rigid approach.

However, considering capitalization as one debt protection measure, without factoring in supply reliability, it would seem reasonable to expect a company which developes significant off-balance sheet financing to counter with equity additions and/or other debt reduction.

In the absence of contractual safeguards embodying sound purchased power economics, situations are likely to arise which will increase a utility's cost of capital. Increased leverage and fixed charges borne by the utility in connection with heavier reliance on purchased power might not be offset by greater regulatory support. Greater reliance on purchased power, especially if costs and reliability are placed outside the utility's control, is highly likely to erode quality and lead to lower Moody's ratings. As an example, if power contracts necessitate large future rate increases, regulators will undoubtedly find ways to minimize these increases, just as they have done with costly rate base additions. Shrinking rate bases together with an inability to cover contract costs and earn a competitive return spells difficulty. The results suggest reduced cash flow, dividend cuts, and a growing perception among investors that the utility in question represents an unattractive investment opportunity. Capital costs will increase, as investors demand an even larger risk premium to compensate for possible loss of value.

An underlying assumption supporting the "independent" approach is that ample power will be available outside the utility, and that their construction can be financed cheaply with lower cost debt capital. A traditional utility capital structure contains not just debt but necessary and relatively more expensive protective cushions of preferred and common stock equity as well. If the capital structure expands in support of rate base additions, and the utility is permitted an adequate and competitive return by regulators, the enterprise will constitute an efficient financial engine. It will be in a position to build new plant in good times and bad sufficient to meet the public's need for power. Without contractual support which may be burdensome to the utility, Moody's questions whether the "independent", relying on debt capital for the most part, will (1) be able to attract the capital necessary to build power projects on reasonable terms, and (2) will have continuous access to financial markets. In other words, substituting plant construction by the "independent" for plant construction by the utility may not provide a panacea for rate increases and other difficulties any more than it is likely to provide a safe haven for investors.

Problems with service could negatively affect credit ratings. If an "independent" turns out to be unreliable, the electric utility will be the one to be blamed, by both customers and regulators. The utilities will have given up control over their generating sources and yet will continue to shoulder the responsibility for problems or changes in economic and legislative conditions. A lose-lose situation could develop from the utility point of view.

Investors will need to focus on a host of reliability issues concerning the "independent", as well as monitor the economic attractiveness of the power supply contract. From a credit standpoint, contracts between the utility and the "independent" which take account of reliability factors such as performance guarantees will be viewed more favorably than those which do not. Moody's will also be interested in the operating history, management expertise, and financial condition of the "independent". We will also be interested in questions regarding environmental standards, local political climate, and transmission adequacy. Utilities contracting with independent power producers which have successfully addressed concerns such as these will have less risk reflected in their credit ratings.

If you detect in these words a sense of disappointment in the regulatory developments of recent years - then you have heard correctly. The undoing of the "regulatory compact" on a broad scale is an important event to all who have a continuing interest in the operating and financial condition of our investor owned utilities. That broken compact needs to be rebuilt or constructively refashioned.

If you detect in these words a sense of concern about greater risk on the horizon for these utilities - then you have heard correctly. The breaking of the "regulatory compact" coupled with the now legendary obstacles to successful plant completion have many managements in a serious "building-averse" frame of mind. The addition of small units supplemented by purchased power may be sufficient as a short range remedy but would not seem to be a very good solution over time. In fact it is probably no solution at all. To have the responsibility to serve a vital need of the public without a firm control of the means to do it, is to be in a difficult position, at best.

If you draw from these thoughts the idea that reliability of power supply is a critical factor in the bond rating process, you are correct. It will not matter that short-sighted regulation impaired the utility operationally and financially. If there is a loss of supply reliability and the public suffers, then the company will absorb the blame and its investors will suffer the consequences. The interaction between the "3Rs", regulation, risk and reliability is critical to the operational and financial strength of a utility company.

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Christine L. Nolin
Executive Director

January 31, 1990

Hon. Bennett Johnston
Chairman
Committee on Energy & Natural Resources
United States Senate
Washington, D.C. 20510-6150

Dear Senator Johnston:

Enclosed are answers of Joseph P. Kearney, CEO of PG&E-Bechtel Generating Company, on behalf of the Cogeneration & Independent Power Coalition of America (CIPCA), to questions received following our testimony before the Committee on Amendment 267 to S.406, the "Competitive Wholesale Electric Generating Act of 1989".

Thank you again for providing us with the opportunity to testify before your Committee. If we can provide any further assistance, please do not hesitate to ask.

Sincerely,

Christine L. Nolin
Executive Director

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RESPONSES OF CIPCA TO QUESTIONS FROM
SENATOR JAMES A. MCCLURE REGARDING
PRINTED AMENDMENT NO. 267

QUESTION NO. 1

Do you support Printed Amendment No. 267 as introduced? If not, what changes would be necessary to secure your support? Please provide the Committee with the statutory language which you would propose to be added.

ANSWER NO. 1

CIPCA supports the introduction of Printed Amendment No. 267 as an essential first step toward the enactment of legislation to amend the Public Utility Holding Company Act. Printed Amendment 267 is narrowly and, in our view, properly crafted to preserve the legitimate functions of PUHCA while eliminating the absolute barrier of non-QF development posed by the statute today. Although we are aware that the legislation is likely to be amended, CIPCA does not now support any specific changes to Printed Amendment No. 267.

QUESTION NO. 2

Would you support PA 267 if the recommendations of the National Association of Regulatory Utility Commissioners are added? See attached summary page of NARUC testimony.

ANSWER NO. 2

NARUC's recommendations involve important and complex issues related to state/federal jurisdiction. These issues predate current proposals for PUHCA reform and are worthy of independent consideration. It is not clear that Printed Amendment No. 267 would alter existing state/federal jurisdictional authority. Moreover, the Amendment includes a specific savings provision intended to preserve the status quo.

CIPCA will continue to review this critical issue because adequate regulatory authority at both the state and federal levels is essential to maintaining the integrity of the competitive power generation market. To the extent this authority is determined to be inadequate or becomes so as the result of the PUHCA reform, CIPCA will propose appropriate statutory or regulatory corrections.

QUESTION NO. 3

Would you support PA 267 if a transmission access or a mandatory wheeling provision is added?

ANSWER NO. 3

The issue of mandatory transmission access is a red herring designed to deter thoughtful consideration of the need for and scope of PUHCA reform. While CIPCA supports regulatory or other incentives to promote voluntary transmission access, we do not believe that mandatory transmission access is essential to foster the further development of the competitive power market at this time. Recent FERC analysis and decisions, as well as recent filings at FERC, indicate that regulatory authority may be available to review any abuse of market power through unfair use of transmission to impede competition among wholesale power generators. The adequacy and efficacy of this authority has yet to be fully determined, but the record to date indicates that changes to the Federal Power Act in this area should not be presumed to be necessary.

In addition, state authority over utility capacity procurement programs may be a remedy for any unfair use of transmission to gain a competitive advantage. As with the issue raised by NARUC, CIPCA will continue to review the adequacy of regulatory authority to prevent unfair use of transmission and will make appropriate recommendations if necessary.

QUESTION NO. 4

PUHCA was enacted to address very serious problems caused by utility holding companies. Is the current absence of abuses evidence that PUHCA has outlived its usefulness, or proof that it continues to work effectively.

ANSWER NO. 4

The question is extremely broad and well outside the intent of Printed Amendment No. 267. The amendment is very narrow, addressing solely the provisions of PUHCA that serve as an absolute barrier to non-QF power development. The Amendment does not effect a repeal of PUHCA.

There is no question that with respect to non-QF development, the restrictions in PUHCA are inappropriate and counter to consumer interests. Expanding supply options in the power generation market will result in increasing competition with resulting consumer benefits. PUHCA currently serves as an obstacle to these consumer goals.

QUESTION NO. 5

What impact would PA 267 have on the structure of the electric utility industry?

ANSWER NO. 5

The Amendment would foster more economic investment, greater efficiency in the market by the resulting increase in competition, and more options to meet power needs. In the absence of PUHCA reform, independent power producers will continue to be forced to structure projects involving multiple partners, uneconomic steam loads and greater costs.

QUESTION NO. 6

What impact would PA 267 have on the price, supply and reliability of electricity?

ANSWER NO. 6

By allowing less burdensome market entry, Printed Amendment No. 267 will result in greater competition and increased efficiency. This will lead to lower prices. Also, by placing the risk of the project on the developer, the competitive power market results in increased incentives for reliable operation. As a corollary, shifting risk to the developer results in decreased economic risk for consumers. CIPCA's written testimony submitted to the Committee details the reliability history of many member company projects. This history demonstrates that when the risk/reward mechanism is properly structured by placing risk on the developer in return for market rewards, system reliability is maintained. Competition also leads to more supply options.

QUESTION NO. 7

A key assumption of PA 267 is that not enough powerplants are now being constructed to meet future power needs. Is that true everywhere, or only in certain states or regions? Do you agree with the assertion made by some that state public utility commissions are primarily to blame for the lack of adequate powerplant construction, or are other factors responsible?

ANSWER NO. 7

Various federal agencies and the North American Reliability Council have predicted the need for upwards of 100,000 Mw of new capacity over the next ten to fifteen years. This need varies from region to region.

The electric utility industry is a complex industry. To the extent there has been a lack of adequate powerplant development, many factors including regulation at the state and federal level are involved. The issue, however, is not who is to blame. Rather, the issue is how best to resolve regulatory issues to insure that consumers receive reliable and competitively priced electricity. PUHCA reform is an essential step in this direction because it provides more power supply options to utilities.

QUESTION NO. 8

What are your views on allowing utility-owned EWGs to sell power to their utility parent?

ANSWER NO. 8

Utility affiliates should not be limited in their ownership of non-QF power facilities. In addition, absolute prohibitions on transactions between a utility owned power generation subsidiary and the utility are contrary to public policy. However, the issue of potential abuses in such transactions is of concern to CIPCA. Adequate regulatory authority to address these abuses must exist. CIPCA is not convinced that existing authority in this area is inadequate.

It is worthy to note that PUHCA itself provides virtually no protection in this area. The statute does not preclude transactions between a power generating subsidiary and its utility parent within the utility's service territory.

QUESTION NO. 9

What are your expectations about how FERC will regulate EWGs? Do you expect that FERC will engage in traditional cost of service regulations, or will it instead allow EWGs to charge "market prices," as has been the direction FERC has recently been heading through a number of case-specific decisions?

ANSWER NO. 9

CIPCA encourages the FERC to continue the development of a body of precedent in support of market based rates. PUHCA reform neither diminishes nor enhances FERC's authority under the Federal Power Act to deviate from cost-of-service ratemaking in appropriate cases. We refer the Committee to CIPCA's comments filed in

QUESTION NO. 10

Would EWGs be "fuel neutral"?

ANSWER NO. 10

Yes, EWGs are fuel neutral -- developers will respond to market conditions. We note that increased competition will result in the presentation of additional fuel and technology choices in the generation of power as has been the demonstrated result of PURPA.

QUESTION NO. 11

One key issue in the PUHCA reform debate is whether IPPs should have an artificial advantage over utility powerplants due to the tax benefits of debt leveraging. A Committee staff analysis concludes that debt leveraging does not create an unfair advantage for IPPs. What are your views?

ANSWER NO. 11

CIPCA concurs in the staff analysis concluding that debt leveraging does not create unfair advantage for IPPs. The Committee staff analysis uses relatively conservative assumptions, and may actually understate the cost of capital to IPPs. Higher degrees of debt leveraging can be obtained by IPPs because of the certainty of the contractual commitments that support all facets of the project: construction, equipment supply, fuel supply, operations, financing as well as power sales. In other words, all parties to major project agreements share in risks. It is important to note that repayment terms for this debt averages twelve (12) to twenty (20) years, significantly shorter than utility bond financing -- clearly a disadvantage for the competitiveness of an IPP project.

The decision to lift the barrier of PUHCA restrictions should be based on whether consumers will receive a better deal as a result. The fact that this issue is seen as "key" by some, would clearly indicate that consumers can get more competitively priced, reliable power through IPPs.

The recent determination by the Virginia Commission that Virginia Power could more effectively and reasonably provide needed new peaking capacity demonstrates that IPPs do not automatically or inherently have an advantage over utility powerplants.

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Executive Director

RESPONSES TO QUESTIONS FROM
SENATOR CONRAD REGARDING
PRINTED AMENDMENT NO. 267

QUESTION NO. 1

The anticipated debt-equity ratios of IPP projects?

ANSWER NO. 1

We expect IPP debt ratios to initially be within a range of 70% to 85% of total capitalization.

QUESTION NO. 2

Whether such facilities would typically be "project-financed" (i.e., through issuance of debt without recourse to parent companies or other third parties)?

ANSWER NO. 2

We expect IPPs in large measure to be project financed. Project finance will continue to be the primary financing technique as the industry evolves. It is important to recognize that "without recourse" it not entirely a correct characterization; this type of financing is more appropriately referred to as "limited recourse." In other words, to support the project the major contract participants take on significant but discrete risks, such as substantial penalties for failure to build the project on schedule or to design performance, or for failure to deliver fuel. The combination of these limited recourse, defined undertakings from substantial parties, in conjunction with sound economics, provides the assurance of project viability.

QUESTION NO. 3

The term of debt financing for such projects?

ANSWER NO. 3

Typical repayment terms are twelve (12) to twenty (20) years, which is significantly shorter than the term of utility bond financing, which disadvantages the competitive position of IPPs.

QUESTION NO. 4

Whether such projects can be financed on economic terms without guaranteed purchase or take-or-pay requirements or similar provisions in their power sales contacts which will assure a stable cash flow?

ANSWER NO. 4

The amount of debt financing on economic terms available for an IPP is in part a function of its reasonably assured stream of power sales revenues. Projects can be structured with a variety of provisions that allow utilities to treat IPPs as economic dispatch units. However, the contract provisions must allow predictable cash flows under a variety of economic scenarios. The revenue stream can come from 1) the ability to sell economically priced power to multiple markets on an as-needed or short-term contractual basis; 2) entering into a long-term power sales agreement that has a minimum dispatch or minimum take provision; or 3) a combination of 1 and 2. Lenders and IPP owners are generally comfortable with the operating risks of IPP's but do need reasonable assurance of market before making an investment. Similarly, utilities that solicit bids for IPP generated power usually are interested in a long-term source of reliable power. Long-term power sales contracts that contain a minimum dispatch or minimum take provision lower the IPP's cost of capital. A portion of this capital cost savings can be shared with the consumer in the form of lower rates.

QUESTION NO. 5

Whether such projects can be financed on economic terms without fuel-cost adjustment or escalator or similar provisions in their power sales contracts which will insulate them from the risk of fuel cost increases?

ANSWER NO. 5

In general, utilities currently pass through the energy portion of costs to ratepayers, and are effectively insulated from fuel cost increases. The fuel supply price escalation risk of an IPP does not have to be assumed by the purchaser in a power sales contract in order to finance the project. The fuel supplier of the IPP can assume this risk and factor it into its product cost. The amount of financing available on economic terms will be dependent on how well the IPP has hedged this risk and/or is being compensated for taking it.

QUESTION NO. 6

What percentage of current Qualifying Facilities have debt-quality ratios exceeding 80-20?

ANSWER NO. 6

We do not have this information.

QUESTION NO. 7

What percentage of QF's are "project-financed"?

ANSWER NO. 7

We believe that the majority of the QF's that are not owned by the host steam user are project financed.

QUESTION NO. 8

The magnitude of risk premiums (i.e., higher debt and/or equity costs as compared with utilities), if any, that have been required to be paid in order to obtain debt and/or equity financing for existing QFs.

ANSWER NO. 8

The debt and equity risk premiums for existing QF's vary and depend on when they were developed; the qualifications and financial strength of the developer, the constructor and operator; the technology employed; and the contractual and operating attributes of the project.

For QF's currently being developed by well qualified firms, the debt risk premium is approximately 100 to 200 basis points and the equity risk premium is approximately 300 to 500 basis points over the utility cost of capital.

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William W. Berry
Chairman and Chief Executive Officer

Dominion
Resources

January 8, 1990

The Honorable J. Bennett Johnston
Chairman
United States Senate
Committee on Energy and Natural Resources
Washington, D. C. 20510-6150

Dear Senator Johnston:

I enclose my responses to the questions from Senators McClure and Conrad.

I appreciate the additional opportunity to comment on this important legislation.

Sincerely,

William W. Berry

William W. Berry

Enclosures

JAN 12 1990

Questions of Senator McClure

1. Do you support Printed Amendment No. 267 as introduced? If not, what changes would be necessary to secure your support? Please provide the Committee with the statutory language which you would propose to be added.

William W. Berry:

Yes. The proposal as it stands would be in the public interest by allowing the emerging competitive market in electric generating capacity to work better.

2. Would you support PA 267 if the recommendations of the National Association of Regulatory Utility Commissioners are added? See attached summary page of NARUC testimony.

William W. Berry:

No. The full recommendations of NARUC are too far-reaching and in part are impractical. I would support a properly drafted amendment affirming the right of state regulatory commissions to review the prudence of wholesale purchases by utilities, other than subsidiaries of integrated multi-state holding companies. This "codification of the Pike County doctrine" could be useful in removing any doubt that state regulators have the authority to determine the prudence of most utility purchasing decisions.

The second NARUC proposal is unnecessary. Nothing in the proposed legislation affects the issues raised in this proposal. An attempt to address them in legislation exempting independent power producers from the Holding Company Act would raise complex and difficult questions concerning Federal-state relations that can only delay the benefits to electricity consumers of more efficient competitive capacity markets.

Through their power to regulate utilities, the states already have sufficient authority and access to records to prevent the abuses of subsidization by ratepayers or unfair self-dealing between a utility and an affiliated supplier. A right of access to the books and records of subsidiaries with no transactions with affiliated utilities is unnecessary to prevent abuses and would lessen competition by deterring many companies from participation in the independent power industry.

The fourth NARUC proposal is unworkable.

3. Would you support PA 267 if a transmission access or a mandatory wheeling provision is added?

   William W. Berry:

   No. There are strong indications that increased transmission access for suppliers to utilities will be provided by utilities through voluntary contracts if FERC removes existing disincentives and allows appropriate cost-based pricing. The pricing must allow recovery of incremental costs if improvements to transmission systems are required and must protect the utility's native customers from costs occasioned by the transmission service. The complex issues involved in transmission access should not be addressed in legislation removing restrictions of the Holding Company Act.

4. PUHCA was enacted to address very serious problems caused by utility holding companies. Is the current absence of abuses evidence that PUHCA has outlived its usefulness, or proof that it continues to work effectively?

   William W. Berry:

   I believe the Public Utility Holding Company Act has outlived its usefulness because other statutes and strengthened state regulation would, in its absence, be ample to prevent the re-emergence of abuses.

   However, the merits of Printed Amendment 267 do not depend on the answer to this question since the amendment does not remove whatever protections the Holding Company Act still provides. Freeing Exempt Wholesale Generators from the '35 Act cannot give rise to the kinds of abuses the Act was designed to correct.

5. What impact would PA 267 have on the structure of the electric utility industry?

   William W. Berry:

   The legislation would result in a somewhat larger share of utility capacity needs being supplied by non-utility power producers. This would be so because freeing independents from the necessity of developing projects under PURPA would avoid unnecessary costs and increase supply. Thus non-utility projects would be more often preferable to utility construction. This would benefit electricity customers.

6. What impact would PA 267 have on the price, supply and reliability of electricity?

William W. Berry:

Prices would be lower because unnecessary costs resulting from project development under PURPA would be avoided and competition would be stronger. Supply would be increased because potentially competitive projects would no longer be lost because of their inability to fit under PURPA.

The amendment would not affect reliability of service. With proper buying practices, utilities can provide reliable service with capacity purchased from either PURPA projects or EWGs.

7. A key assumption of PA 267 is that not enough powerplants are now being constructed to meet future power needs. Is that true everywhere, or only in certain states or regions? Do you agree with the assertion made by some that state public utility commissions are primarily to blame for the lack of adequate powerplant construction, or are other factors responsible?

William W. Berry:

I would say that a key basis for PA 267 is that non-utility projects can play an important role in meeting future capacity needs economically and that the ability to develop plants outside PURPA can enhance the benefits of this additional source of capacity supply.

Virginia Power is not buying from independents because it is unable to build. It is buying because in many cases the prices and terms offered by independents provide a better deal for our customers than utility construction. As I've already noted, the ability to develop independent projects without contriving steam uses will improve those terms and conditions. Virginia and other areas, especially in the northeast, are already engaged in adding capacity to meet growing demand and most states and regions will face capacity needs during the 1990s. As these needs become imminent, they will want the option of buying capacity in the open and efficient competitive market that PA 267 can help create.

In some cases, disincentives to utility construction resulting from prudence disallowances or inadequate returns may result in insufficient capacity additions or bias the selection of capacity toward units with low risks. But even if these disincentives did not exist, utilities and their customers benefit by having the option of buying capacity in competitive markets that foster efficiency and allow the selection of the most competitive independent and utility projects.

8. What are your views on allowing utility-owned EWGs to sell power to their utility parent?

William W. Berry:

The decision on whether to allow EWGs -- and PURPA projects, as well -- to sell to a utility with which they are affiliated should be determined by the utilities' regulators.

If the company owning the affiliated utility and independent producer desire affiliated transactions, the utility's regulator(s) must decide whether to allow the sales and how they will be policed to prevent unfair self-dealing. Each state's policy on self-dealing can be established in setting up the bidding system for capacity purchases.

Dominion Resources' decision is that its affiliates will not participate in the bidding on Virginia Power's needs and that any capacity developed by Virginia Power will be traditional utility capacity subject to regulatory approval and pricing. The bidding policy adopted by the Virginia State Corporation Commission rules out participation in utility solicitation by affiliates of the buying utility.

9. What are your expectations about how FERC will regulate EWGs? Do you expect that FERC will engage in traditional cost of service regulation, or will it instead allow EWGs to charge "market prices," as has been the direction FERC has recently been heading through a number of case-specific decisions?

William W. Berry:

I expect that FERC's regulation of EWGs will depend upon the EWG's situation in each case. I would expect that an EWG with market power -- because, for example, an affiliated utility controlled transmission access that restricted the buyer's supply options -- would be subject to traditional cost of service regulation.

On the other hand, I would expect an EWG without market power to be allowed market pricing of its sale. FERC has been carefully considering, in both a proposed generic rule and in a series of specific cases, the circumstances under which flexible pricing is permissible and in the public interest. Basically, I expect market pricing to be allowed where the facts show that competition is adequately protecting the public.

10. Would EWGs be "fuel neutral"?

William W. Berry:

The fuel mix of purchased capacity can be determined by the buying utility through its buying system, as Virginia Power has demonstrated. Allowing independent projects to develop outside PURPA would not change this fact. It would, however, remove artificial impediments to the development of larger coal-fired projects and gas turbines by independent producers and thus have the significant advantge of leveling up the playing field for different types of projects.

11. One key issue in the PUHCA reform debate is whether IPPs would have an artificial advantage over utility powerplants due to the tax benefits of debt leveraging. A Committee staff analysis concludes that debt leveraging does not create an unfair advantage for IPPs. What are your views?

William W. Berry:

I believe debt leveraging by independent producers does not create an "unfair advantage." Capital structure is only one of many ways in which independent projects differ from utility projects and the more leveraged structures usually seen in independent projects are evidently appropriate for the independent power business. My views on this matter are set forth in my written statement to the Committee of November 16, 1989 on pages 10 and 11.

Additional Questions from Senator Conrad

The committee heard testimony that Independent Power Producers would enjoy an advantage over utility power plants under the bill because of the tax benefits of debt leveraging. In that regard, what information do you have that would indicate:

1. The anticipated debt-equity ratios of IPP projects.

   William W. Berry:

   The debt-equity ratio for IPP projects will be similar to those of recent QF projects, typically involving debt ratios of 80 percent or more.

2. Whether such facilities would typically be "project-financed" (i.e., through issuance of debt without recourse to parent companies or other third parties).

   William W. Berry:

   Project financing would be typical. The review of the lenders to such projects provides additional assurance of the projects' viability.

3. The term of debt financing for such projects.

   William W. Berry:

   The financing term would depend upon the terms of the power purchase agreement. For 20 year power contracts, financing terms of 12 to 15 years would be possible.

4. Whether such projects can be financed on economic terms without guaranteed purchase or take-or-pay requirements or similar provisions in their power sales contracts which will assure a stable cash flow.

   William W. Berry:

   Contracts being signed nowadays do not typically involve either "guaranteed purchases" or "take-or-pay provisions." Instead, they provide for capacity payments to be made subject to performance (availability at a specified level, etc.). Energy payments will depend on the amount of generation by the project, which is increasingly subject to the buying utility's control, possibly within some limits.

   Contracts with performance-based capacity payments can be financed. To the extent that these payments are at risk for events beyond the control of the producer (for example, regulatory disallowances), the project costs may be increased or financing may be impossible.

5. Whether such projects can be financed on economic terms without fuel-cost adjustment or escalator or similar provisions in their power sales contracts which will insulate them from the risk of fuel cost increases.

William W. Berry:

Projects imposing long-term general fuel-cost risks on independent producers are virtually impossible to finance. General fuel price risk should be borne by the buying utility and its customers, as it is when utilities build under traditional regulation. This does not mean that contracts must provide a fuel cost pass-through. If fuel-cost adjustments are based on a general index, the independent developer can and should be held responsible for efficiency in fuel procurement sufficient to match or outperform the index.

6. What percentage of current Qualifying Facilities have debt-equity ratios exceeding 80-20.

7. What percentage of QFs are "project-financed."

William W. Berry:

I have no exact information on these points. As indicated above, most projects have debt ratios of 80 percent or more and are project-financed.

8. The magnitude of the risk premiums (i.e., higher debt and/or equity costs as compared with utilities), if any, that have been required to be paid in order to obtain debt and/or equity financing for existing QFs.

William W. Berry:

The magnitude of the risk premium depends very much on the specifics of each project. The assumption by the independent producers of financing, construction and operating risks probably requires equity premiums at least 500 basis points over earned utility returns.

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January 12, 1990

The Honorable J. Bennett Johnston
Chairman
Committee on Energy and Natural Resources
United States Senate
Washington, D.C. 20515-6150

Re: Followup questions on Amendment 267 to S. 406, the "Competitive Wholesale Electric Generation Act of 1989"

Dear Chairman Johnston:

Thank you very much for your letter of December 20, 1989 requesting the responses of the National Association of Regulatory Utility Commissioners (NARUC) to a series of post-hearing questions posed by Senators McClure and Conrad. The NARUC greatly appreciates this opportunity to provide its views on the important issues raised by these questions. We also deeply appreciate your efforts to include an NARUC representative at the November 16, 1989 hearing on the above-referenced legislation.

In the view of the NARUC, this legislation, which would amend the Public Utility Holding Company Act (PUHCA) to exempt owners of "exempt wholesale generators" (EWGs) from its coverage, is crucially important legislation, which, if enacted, would fundamentally restructure the investor-owned electric utility industry. As reflected in our "Resolution on Reform of the Public Utility Holding Company Act" (enclosed herewith), the State commission members of the Association strongly oppose this legislation unless "provisions are included which specifically preserve the legal authority of the respective State commissions to insure that the sale of power by new entrants into wholesale markets is in the interest of retail ratepayers." Stated simply, the NARUC cannot support legislation which envisions a utility industry reliant on purchased power unless State commissions are afforded the clear and uncontestable legal authority to ensure that the resource acquisitions plans of retail utilities are in the interest of retail ratepayers. As explained in our November 16 testimony and in the responses to Senator McClure's questions which follow, under current law, there is no such assurance.

RESPONSES TO THE QUESTIONS OF SENATOR MCCLURE

1. **Do you support Printed Amendment No. 267 as introduced? If not, what changes would be necessary to secure your support? Please provide the Committee with the statutory language which you would propose to be added.**

NARUC Response: As stated above and in our enclosed resolution, the NARUC strongly opposes the legislation as introduced. This opposition will not be overcome unless the bill is amended in four respects:

First: The legislation must "ensure the right of each State commission to review the prudence of the wholesale purchasing practices of each distribution utility subject to the State commission's authority."

By this language, we propose that specific provisions be included in the bill which ensure that the Supreme Court's decision in Mississippi Power & Light v. Mississippi, 108 S.Ct. 2428 (1988) (MP&L) could not be used by retail utilities purchasing power generated by EWGs to force State commissions to automatically passthrough the costs of such power to retail consumers. Under MP&L and earlier decisions of the Supreme Court[1] and State courts[2], retail utilities have repeatedly argued that wholesale rates approved or accepted by the Federal Energy Regulatory Commission (FERC) under the Federal Power Act, or wholesale power entitlements allocated by FERC between retail utility subsidiaries, establish unreviewable costs which State commissions must allow retail utilities to collect from their residential, commercial and industrial customers. In response, State commissions have asserted that under the principles of the Pike County decision[3] and other rulings[4], a State commission is not legally required to passthrough the costs attributable to FERC-approved wholesale rates if the State commission determines that the retail utility purchaser had not exercised prudence in examining and acting on all of its supply options.

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[1] Nantahala Power & Light Co. v. Thornburg, 476 U.S. 953 (1986).

[2] E.G. Northern States Power Co. v. Minnesota PUC, 344 N.W.2d 374 (Minn. 1984); Northern States Power Co. v. Hagen, 314 N.W.2d 32 (N.D. 1981); Narragansett Electric Co. v. Burke, 381 A.2d 1358 (R.I. 1977).

Despite the assertions of many that preemption under MP&L is limited to the integrated holding company context, retail utilities continue to litigate the passthrough issue in nonholding company situations. For example, on September 29, 1989, San Diego Gas & Electric Company (SDG&E) filed a complaint in U.S. District Court against the California PUC requesting a declaratory order and permanent injunction against the California commission which would declare "that the rates paid by SDG&E under [FERC-approved] contracts are binding on the CPUC and are operating costs which SDG&E must be allowed currently to recover from its ratepayers." See complaint (enclosed herewith) at page 13.

This complaint is notable for a number of reasons:

First, the utility bases its claim for relief on Nantahala and MP&L even though the issue does not involve an FERC allocation of purchased power costs among the operating subsidiaries of a holding company. Rather, the company cites language in Nantahala for the proposition that all wholesale power contracts accepted by FERC establish rates which are binding on the States. Complaint at 11-12. Clearly, SDG&E does not believe that MP&L and Nantahala can be confined to the registered holding company context.

Second, not only does the utility believe that these cases preempt a State's right to review the prudence of wholesale power purchases by a retail utility, the company also asserts that such preemption is sweeping enough to require a State commission to reflect the cost of purchased power through an adjustment clause. Specifically, SDG&E has asked the Federal District Court to require the CPUC "to permit SDG&E to include such [purchased power] costs in, or restore them to, its ECAC [Energy Cost Adjustment Clause] account." Complaint at 14.

Third, as independent grounds for relief, the utility claims that the CPUC has violated its civil rights and therefore, it is entitled to relief under 42 U.S.C. sec. 1983. While it appears that this claim is in some sense derivative of the MP&L preemption claim, the company must believe that it has a colorable independent claim for injunctive relief on civil rights grounds.

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[3] Pike County Light & Power Co. v. Pennsylvania PUC, 465 A.2d 735 (Pa. Comm. Ct. 1983).

[4] E.G. Kentucky West Virginia Gas Co. v. Pennsylvania PUC, 837 F.2d 600 (3d Cir. 1988), cert. denied, 109 S.Ct. 365 (1988).

Fourth, unlike MP&L, Nantahala, Pike County and Narragansett, which were litigated through the State courts, this case has been brought in Federal court. As these earlier cases make quite clear, State courts are fully capable of deciding questions of Federal preemption under the Federal Power Act. However, rather than appeal the CPUC's order under normal State procedures, the company apparently prefers a Federal forum.[5]

In sum, by its actions, SDG&E has clearly indicated that at least one utility believes it has a Federal right, enforceable in Federal court, to recover all of its purchased power costs, whether prudently incurred or not, irrespective of the State commission's contrary findings.

Despite this continuing litigation, many witnesses at the recent hearings asserted that the law was clear on this point, and therefore that there was no need to "codify Pike County", or that the issue of clear State authority to review wholesale purchases was not relevant to the legislation. While we agree with that view of existing law, we respectfully disagree with the notion that the issue is so clear. First of all, the law is not clear, a fact that the legislation itself recognizes in the section 4 "savings clause" and its description in the statement accompanying introduction of the legislation. Conversely, if "the State commissions have all the authority they need already", what would be the problem with amending the legislation to "restate the obvious?" The legal certainty of codification would inure to everyone's benefit.

Secondly, the issue is directly relevant. As it stands, the bill, coupled with the MP&L decision, would substantially reduce State authority over a utility's resource acquisition plans. Consider the following simple example of the effect of the legislation: Assume the existence of a single vertically integrated retail utility, having no affiliates, which owns one generating plant that is held in its retail rate base. The State commission in the jurisdiction in which the utility operates has sole regulatory authority to regulate the utility's power supplies. Assume further that after passage of Amendment No. 267, the utility chooses to purchase capacity or energy from an EWG under a purchase contract approved by the FERC under the Federal Power Act. To the extent that MP&L requires the State commission to passthrough the costs of the utility's EWG purchase, the State commission has lost authority to regulate power supply acquisitions. The fact that the utility has more choices says nothing about the scope of State regulatory jurisdiction unless the States have the clearly established independent authority to review the utility's decisions with respect to each of those choices.

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[5] In light of the Supreme Court's very recent decision in New Orleans Public Service Inc. v. City of New Orleans, 109 S.Ct. 2506 (1989), utilities will have their choice of a State or Federal judicial forum to pursue their preemptive claims against State commission review of wholesale purchasing practices.

Therefore, unless State authority to review a retail utility's acquisition of resources from all sources, including demand side measures, is guaranteed, the affect of the legislation, whose express purpose is to increase the opportunities for wholesale power suppliers to entire generating markets, will be the erosion of the States' ability to protect consumers. Every utility decision to substitute a wholesale purchase from an EWG for construction of its own capacity in retail ratebase will reduce State regulatory authority to the extent of that purchase.

In sum, to guarantee the authority of State commissions over resource acquisition, section 4 of the legislation must be replaced with a provision which affirmatively codifies the authority of State commissions to review the prudence of retail utility participation in wholesale power markets. We have enclosed a document entitled "Codification of Pike County/Regional Board -- Combined Further Redraft of 7/19/89" which includes statutory language to implement points one and four of our resolution.[6] We would be pleased to work with you and your Staff to polish the language of the draft, but we believe that this provision, or language which accomplishes the same purpose, is absolutely necessary if this legislation is to proceed to passage.

Second: The legislation must "preserve the right of each State commission to conduct bidding programs and least cost planning; to determine the appropriate mix of generation, as a matter of fuel and technology choice and as a matter of ownership; to take actions to ensure system reliability; to restrict of prohibit affiliate transactions; and to approve or disapprove the transfer of assets from a utility to another party, free from preemption under Federal statutes or the Commerce Clause."

The purpose of the second point of our resolution is related to the first: to ensure that State regulation of a utility's involvement in the new, more competitive power supply markets fostered by PA No. 267 is free from interference. As we described in our November 16 testimony, many State commissions have begun the process of implementing competitive procedures for the acquisition of new sources of supply -- initiatives entirely consistent with the purpose of the legislation before the Committee. Because these processes will necessarily involve retail utility participation in FERC-regulated wholesale power markets, the threat of preemption under MP&L will be ever present unless the bill is amended to protect these nascent State programs from preemption.

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[6] Copies of this document have previously been provided to the Staff of the Committee for their review and comment.

Third: The legislation must "provide a right of access, enabling State commissions to review the books and records of holding companies and all holding company subsidiaries, including non-regulated businesses, that transact business with the retail distribution company or EWG entity."

Again returning to our November 16 written statement, the purpose of this element of our resolution is to provide State commissions a means to enforce the subpoenas, discovery orders and data requests they have issued against entities not physically located within State boundaries but transacting business in ways that affect the price or reliability of retail electricity sales. This provision is intended to be essentially procedural in character, providing State commissions with no new substantive jurisdiction beyond what is given them through the provisions of State law.

Fourth: "In the case of an integrated multi-state utility holding company, [the legislation must be amended to] authorize regional compacts for those States who have jurisdiction over retail subsidiaries of the holding company for the sole purpose of regulating the allocation of costs and/or the prudence of wholesale power purchases."

The purpose of this provision is to enable those State commissions regulating the operating subsidiaries of a registered holding company to review the prudence of EWG and other wholesale purchases by the company for "system supply", i.e. power acquired to meet the needs of more than one holding company subsidiary. We propose that this first step into regional regulation be voluntary on the part of the States and that the activities of the regional board be focussed on holding company acquisition and allocation of wholesale power.

We enclose herewith a copy of a Discussion Draft dated September 12, 1989 entitled "Outline of Proposed Procedures for Regulation of Multi-state Utility Power Purchases by Regional Boards." This draft is intended to describe the issues suitable for regional board consideration, the procedural schedule for resolution of those issues, and the conditions under which the regional body would operate. Again, we would be happy to discuss this issue and specific legislative language with you and your Staff.

Returning to Senator McClure's first question, the NARUC cannot support the legislation as it now stands. We would be pleased, however, to continue discussing these issues with you, your Staff, and other interested parties as the debate continues.

2. Would you support PA 267 if a transmission access or a mandatory wheeling provision is added?

NARUC Response: There are transmission issue inherently raised by the bill, but NARUC has not prepared a specific response to them. The Association is in the process of formulating its policy with respect to wheeling and transmission issues, particularly in light of the recent report of the FERC Task Force. However, the addition of such a provision to PA 267 is not one of the four points listed in the NARUC resolution.

3. PUHCA was enacted to address very serious problems caused by utility holding companies. Is the current absence of abuses evidence that PUHCA has outlived its usefulness, or proof that it continues to work effectively?

NARUC Response: Following its enactment in 1935, PUHCA led to the substantial restructuring of the industry through divestiture and reorganization to simplify utility operations and financing. PUHCA also erected barriers to the kinds of abuses which had prompted the enactment of the Act. Accordingly, many of the pre-PUHCA "problems" have been prevented due to the radical transformation of the industry caused by the Act.

If PUHCA is to be amended in ways that recreate the opportunity for such problems, other regulatory structures and procedures must be in place to ensure that the pre-PUHCA abuses do not recur. To the extent that State regulation of retail utility companies can prevent such abuses, the jurisdictional authority of the States must be free from doubt. This is precisely the point of the NARUC resolution: if the State commissions are to be relied upon to ensure that an industry freed from PUHCA operates in the public interest, then the States are entitled to the concrete assurance that the actions they take to protect the public from "problems caused by utility holding companies" will not be preempted by subsequent litigation. Consider an example: one area of great concern to the drafters of PUHCA was abuse of utility consumers through self-dealing among holding company affiliates.

As drafted, PA 267 places no special restrictions on the activities of EWGs who are affiliated with retail companies or their parents. Therefore, consumer protections are to be left to State regulators. However, it serves no purpose to rely on State regulation for such protection if the State commissions lack the clear authority or necessary tools to police self-dealing issues.

4. **What impact would PA 267 have on the structure of the electric utility industry?**

NARUC Response: Historically, the investor-owned electric utility industry has been vertically integrated, meaning that a utility providing service in its franchised service territory owned and operated generating, transmission, and distribution facilities sufficienct to meet the needs of its customers. The assumption underlying this legislation is that the industry will operate more efficiently if it is disaggregated, i.e. if ownership of new generation facilities is separated from ownership of transmission and distribution thereby enabling retail companies to acquire new power supplies via contract with EWGs rather than through their own construction programs.

The extent to which the legislation would actually disintegrate any given utility's electric service will of course depend on each company's particular circumstances. However, there can be little doubt that the thrust of the legislation is to place new generating capacity in the hands of parties other than retail utilities.

5. **What impact would PA 267 have on the price, supply and reliability of electricity?**

NARUC Response: The effect of the legislation on these issues is a matter of considerable speculation and controversy. Clearly, unless their efforts are preempted by such decisions as MP&L, the State commissions will continue to endeavor to ensure that retail ratepayers enjoy a reliable supply of power at reasonable prices. By shifting new sources of supply to "contract power" rather than retail ratebase, however, the bill would greatly frustrate, and in the worst case defeat, the efforts of the States to maintain reliable and affordable supplies of electricity unless their legal authority to review wholesale power supply contracts is made crystal clear.

It is for this very reason that the NARUC included point 2 in its resolution. That provision states the Association's policy opposing enactment of this legislation without the specific assurance that State efforts to ensure reliability, efficient and least cost operations, and other ratepayer protections will be free from interference and frustration simply because retail utilities purchase power at wholesale for distribution to their customers.

6. A key assumption of PA 267 is that not enough powerplants are now being constructed to meet future power needs. Is that true everywhere, or only in certain states or regions? Do you agree with the assertion made by some that state public utility commissions are primarily to blame for the lack of adequate powerplant construction, or are other factors responsible?

NARUC Response: We strongly disagree with the assertion that State commissions are "to blame for the lack of adequate powerplant construction," nor do we agree with the premise of the question about the lack of powerplant construction. We recognize, however, that the Committee has heard such allegations from a number of sources who support the enactment of the legislation, but we submit that based upon wide variations in reserve margins, one cannot reasonably draw any Nationwide conclusions. Moreover, if lack of capacity were a serious problem, it would have been addressed in State legislatures by now.

In our view, the more important question raised by these allegations is the apparent belief that this legislation would remedy this "problem." If one assumes that utilities have not been building needed power plants due to the actions of State regulators, and if one further assumes that PA 267 will "unleash" parties to begin construction of "wholesale powerplants", then it necessarily follows that the result of the bill will be to remove the economic consequences of new plant construction from the purview of the State commissions. It is fairly easy to see how this would work: Rather than build a given plant in retail rate base, a utility would instead contract, perhaps with an affiliated EWG, for the same quantity of new capacity. Once the terms of the wholesale sale had received FERC approval, the retail utility would then claim that it enjoyed the unfettered right to pass its purchased power costs through to its retail customers. Stated simply, this legislation is a remedy for "bad retail regulation" only if it allows retail utilities to transfer regulation of their acquisition of supply from their State and local regulators to the FERC.

7. What are your views on allowing utility-owned EWGs to sell power to their utility parent?

NARUC Response: **Assuming that the bill is not amended to** abolish or regulate such affiliate transactions at the Federal level, it is our view that the authority of the State commissions "to restrict of prohibit affiliate transactions" must be specifically affirmed through appropriate amendments. This should be a matter for States to decide based upon individual circumstances. Many State commissions share the concern underlying this question that EWGs selling power to retail affiliates may have an unfair competitive advantage, and accordingly, State commissions have implemented rules or policies to regulate or prohibit this practice. However, as in other areas of State regulation of wholesale power purchases, the danger that these rules and policies will be preempted is ever present. In our view, parties who are concerned about affiliate transactions should support amendments to the bill which ensure that State commissions have the full authority to regulate, restrict, or abolish self-dealing.

8. **What are your expectations about how FERC will regulate EWGs? Do you expect that FERC will engage in traditional cost of service regulation, or will it instead allow EWGs to charge "market prices," as has been the direction FERC has recently been heading through a number of case-specific decisions?**

NARUC Response: We would expect FERC to continue its efforts to reform its wholesale pricing policies, although recent changes in personnel at the Commission may slow the pace of those changes. It is important, however, to keep in mind that FERC policies with respect to wholesale pricing are as important to the development of an independent power industry as amendments to PUHCA.

Our experience under section 210 of the Public Utility Regulatory Policies Act (PURPA) bears out this analysis. PURPA gave three basis benefits to the developers of small power facilities and cogenerators (collectively "QFs"): QF ownership was exempted from PUHCA, utilities were legally obligated to purchase QF power, and importantly, QFs were relieved of the need to obtain FERC approval for the rates at which they sold their power at wholesale. By pricing QF output with reference to the costs of the purchasing utility (i.e. the "avoided cost" standard), PURPA permits these wholesale producers to escape cost-based ratemaking under the Federal Power Act with its attendant regulatory costs. The result is that the purchasing practices of the retail utilities acquiring QF power are the points of contact with the regulatory process, and not the QFs'individual costs. As a practical matter, this means that QFs do not have to prepare and submit cost-of-service studies for regulatory approval, file tariffs, maintain their accounts in compliance with the Uniform System of Accounts, submit annual reports to FERC, or comply with the panoply of other FPA requirements.

PA 267 would give EWGs but one of these three benefits -- exemption from PUHCA. Indeed, the Statement of Introduction accompanying this legislation forswears any intent to deal with FERC ratemaking issues. Accordingly, EWG wholesale sales would remain subject to the full coverage of the FPA with its attendant regulatory obligations, and EWGs would enjoy no legal right to demand that any retail utility purchase their output other than what they could obtain via contract. As a result, if the bill were enacted, the owners of EWGs would be expected to bring substantial pressure on the FERC and the Congress to exempt them from cost-of service ratemaking under the FPA.[7]

The point here is simple enough: as far as EWGs are concerned, their ability to enter wholesale power markets through PUHCA exemption and the methods by which the prices for their output are determined are unquestionably linked. In our view, however, the more important issue is that regardless of how FERC handles wholesale pricing, the only way to ensure that the benefits of competition in generation markets are realized by retail ratepayers is through unquestioned State commission authority over the purchasing practices of retail utilities. It is inescapable that State commissions alone are positioned to discipline the purchasing practices of retail utilities in a competitive market, whether wholesale sales are priced on the basis of costs or market factors.

9. Would EWGs be "fuel neutral"?

NARUC Response: The assumption of many participants in this debate is that the vast majority of new EWG capacity would be gas-fired, for a variety of financial, economic, and environmental reasons. However, on its face, PA 267 does not discriminate in favor or against any fuel or technology choice an EWG might make. Accordingly, EWGs can be expected to undertake the same sort of decisionmaking process as utilities as they consider the size and types of plants they will construct, and reach the same general conclusions. In addition, State commissions may decided to structure their competitive procurement programs to ensure fuel diversity.

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[7] There is substantial question whether FERC could depart from cost-of-service pricing policies on its own without Congressional authorization. See Farmers Union Central Exchange, Inc. v. FERC, 734 F.2d 1486 (D.C. Cir. 1984), cert. denied 469 U.S. 1034 (1984). See also, Griggs, "Competitive Bidding and Independent Power Producers: Is Deregulation Coming to the Electric Utility Industry?", 9 Energy L.J. 415 (1988).

10. One key issue in the PUHCA reform debate is whether IPPs would have an artificial advantage over utility powerplants due to the tax benefits of debt leveraging. A Committee staff analysis concludes that debt leveraging does not create an unfair advantage for IPPs. What are your views?

NARUC Response: The NARUC cannot lend its support to either side of this debate. However, to the extent that EWGs are exempt from the kinds of debt/equity ratios that govern utility-owned investments in generating capacity, their cost of capital will probably differ from utility costs.[8] Whether this difference will confer a competitive advantage on EWGs will depend on a host of other financial, economic and regulatory factors.

To the extent that leveraging may affect the price or reliability of supply, State commissions are capable of ensuring that retail utilities purchase power from reliable and financially sound sources. We would expect that State commissioners will be concerned with the financial viability of all power suppliers, and further, will seek to ensure that participants in competitive bidding procedures compete on even terms. Through the rules they make for competitive power procurement and their oversight of power purchase contracts, State commissions will perform these functions, provided that their efforts are free from preemption through FERC interpretations of the FPA or court decisions which rely on MP&L. Again, it is for this very reason that point 2 is included in the NARUC resolution.

RESPONSE TO THE QUESTIONS OF SENATOR CONRAD

Each of the questions posed by Senator Conrad concerns the manner in which Independent Power Producers will be financed. The NARUC has made no independent assessment of this issue, nor have we collected information concerning the experience thus far with respect to QF financing. Therefore, we have no specific information to offer in response to these questions.

We do note, however, that some of the Senator's apparent concerns will be part and parcel of the State regulatory process, provided that the States are free to make such decisions. For example, with respect to the terms of power sales contracts (questions 4 and 5), State commissions might well determine that retail utilities which sign contracts with high take-or-pay clauses, indefinite price escalators, favored-nation clauses and the like have acted imprudently by shifting too great a risk to their ratepayers. Similarly, as discussed above, State commissions might find that highly leveraged EWGs do not constitute the most reliable options for new supplies and therefore, should be rejected by the retail utilities they regulate. Or State commissions might determine that retail utilities should pursue demand-side investments as an alternative to the acquisition of any new capacity regardless of the source. Under no circumstances, however, should the authority of the State commissions to make these decisions be at risk.

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[8] This assumes that EWGs enjoy the same sort of freedom from FERC-implemented cost-of-service regulation as QFs. This may not necessarily be the case. *See* n. 7 above.

In conclusion, the members of the NARUC greatly appreciate this opportunity to supplement the record with our responses to these important issues. We look forward to working with you, the other members of the Committee, and your fine Staff in the weeks and months ahead.

With best wishes, I am

Sincerely yours,

Charles D. Gray

Charles D. Gray
Assistant General Counsel

Enclosures

Convention Resolution No. 2

Resolution on Reform of the Public Utility Holding Company Act

WHEREAS, Legislation is pending before the Senate Committee on Energy and Natural Resources, S. 406, to amend the Public Utility Holding Company Act of 1935 (PUHCA); and

WHEREAS, The legislation would create a new category of electric generator called Exempt Wholesale Generators (EWGs) which would not be subject to the regulatory restrictions imposed on holding companies by PUHCA; and

WHEREAS, The purpose of this bill is to greatly reduce the barriers to entry for holding companies, including electric utilities, to enter wholesale markets and sell power to distribution utilities for resale to consumers; and

WHEREAS, The addition of new EWGs to wholesale markets subject to regulation by the Federal Energy Regulatory Commission (FERC) will erode State control of an increasingly large percentage of the cost of electrical service, particularly if the FERC and the Federal Courts continue to hold, in reliance on Mississippi Power & Light v. Mississippi ex rel. Moore, 487 U.S. __ (1988), that State commissions have severely limited jurisdiction to review the passthrough of purchased power costs in retail rates; and

WHEREAS, By permitting unrestricted utility ownership of EWGs, the legislation creates the opportunity for utilities to cross-subsidize their construction and operation of wholesale power facilities through their retail distribution rates, particularly utilities owning and operating EWGs which sell power to affiliated distribution companies; and

WHEREAS, The substance of this Resolution is reflected by the Resolution of the same Title adopted by the NARUC Executive Committee on July 27, 1989; now, therefore, be it

RESOLVED, That the National Association of Regulatory Utility Commissioners (NARUC), convened in its 101st Annual Convention in Boston, Massachusetts, strongly opposes amendment to the Public Utility Holding Company Act of 1935 unless provisions are included which specifically preserve the legal authority of the respective State commissions to insure that the sale of power by new entrants into wholesale markets is in the interest of retail ratepayers. Such provisions must:

(1) Ensure the right of each State commission to review the prudence of the wholesale purchasing practices of each distribution utility subject to the State commission's authority; and

(2) Preserve the right of each State commission to conduct bidding programs and least cost planning; to determine the appropriate mix of generation, as a matter of fuel and technology choice and as a matter of ownership; to take actions to insure system reliability; to restrict or prohibit affiliate transactions;

and to approve or disapprove the transfer of assets from a utility to another party, free from preemption under Federal statutes or the Commerce Clause; and

(3) Provide a right of access, enabling State commissions to review the books and records of holding companies and all holding company subsidiaries, including non-regulated businesses that transact business with the retail distribution company or EWG entity; and

(4) In the case of an integrated multi-State utility holding company, authorize regional compacts for those States who have jurisdiction over retail subsidiaries of the holding company for the sole purpose of regulating the allocation of costs and/or the prudence of wholesale power purchases by the holding company.

Sponsored by the Committees on Electricity, Energy Conservation,
and Finance and Technology
Adopted November 15, 1989

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ORIGINAL
FILED
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RICHARD W. WIEKING
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SAN FRANCISCO

United States District Court

Northern District of California

SAN DIEGO GAS & ELECTRIC COMPANY,
Plaintiff,
vs.
THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA; and G. MITCHELL WILK (PRESIDENT), FREDERICK R. DUDA, JOHN B. OHANIAN, STANLEY W. HULETT, and PATRICIA M. ECKERT, members of said PUBLIC UTILITIES COMMISSION,
Defendants.

C 89 3551 WW
Civil Action No.
(Other Action)

COMPLAINT FOR INJUNCTIVE AND DECLARATORY RELIEF

Plaintiff, SAN DIEGO GAS & ELECTRIC COMPANY (hereinafter "SDG&E"), states the following claims for permanent injunctive relief and declaratory judgment against defendants:

JURISDICTION

1. This Court has jurisdiction under 28 U.S.C. §§ 1331, 1337 and 1343 and 16 U.S.C. § 825p. The action arises under the Constitution and laws of the United States, including the Supremacy Clause (art. 6, cl. 2) of the United States Constitution; the Federal Power Act, 16 U.S.C. § 791a, et seq.; 42 U.S.C. § 7151, et seq.; and 18 C.F.R. § 1.101, et seq. (1986). Jurisdiction to grant declaratory relief is conferred by 28 U.S.C. § 2201.

2. Venue is proper in this district under 28 U.S.C. § 1391(b). All of the defendants reside in and the claims arose in this judicial district.

PARTIES

3. Plaintiff, SDG&E, is a corporation organized and existing under the laws of the State of California, with its principal place of business in San Diego, California. SDG&E is engaged in the generation, the wholesale purchase, sale, and transmission of electric power in interstate and foreign commerce, and the transmission, distribution and sale of electric energy and power at retail within San Diego and Orange Counties, California. It is a public utility within the meaning of Article XII of the California Constitution and as such is subject to the jurisdiction of defendant The Public Utilities Commission of the State of California

("CPUC") with respect to retail rates charged by SDG&E to its California customers. SDG&E is also a "public utility" as defined in section 201(e) of the Federal Power Act (16 U.S.C. § 824(e)) and, as such, is subject to the exclusive jurisdiction of the Federal Energy Regulatory Commission ("FERC") with respect to its contracts for the sale and purchase of electric energy and power at wholesale in interstate commerce.

4. Defendant CPUC is an agency empowered by the Constitution and laws of California to fix rates and establish rules for public utilities subject to its jurisdiction. Defendants G. Mitchell Wilk (President), Frederick R. Duda, John B. Ohanian, Stanley W. Hulett, and Patricia M. Eckert are the Commissioners of CPUC and are sued in their official capacities.

BACKGROUND

5. FERC is an independent regulatory agency within the United States Department of Energy, created under 42 U.S.C. §§ 7151 and 7171. As successor to the Federal Power Commission, it is empowered under the Federal Power Act (16 U.S.C. § 791a, et seq.) to ensure that rates charged for the wholesale sale of electric power in interstate commerce are "just and reasonable" (16 U.S.C. §§ 824d, 824e), to promote the interstate interconnection and coordination of electric power generation (16 U.S.C. § 824a(a)), to order physical connection of transmission facilities for electric power where "necessary or appropriate in the public interest"

(16 U.S.C. § 824a(b)), and to investigate and promulgate orders, rules and regulations "as it may find necessary or appropriate to carry out the provisions" of the Act (16 U.S.C. §§ 825f, 825h). Within the area of its authority, the jurisdiction of FERC is exclusive and preempts the authority of any state regulatory agency.

6. This action arises from defendants' unlawful refusal to allow as reasonable operating expenses of SDG&E rates paid by it for interstate wholesale purchases of firm electric power, even though those rates have previously been accepted for filing as "just and reasonable" rates by FERC in the exercise of its exclusive regulatory jurisdiction. These rates are contained in long-term contracts for the sale and purchase of firm power between SDG&E and the Tucson Electric Power Company ("TEP") and the Public Service Company of New Mexico ("PNM") which have been filed with and accepted for filing by FERC.

7. In 1978, SDG&E, together with the Arizona Public Service Company, committed itself to construct the Southwest Power Line ("SWPL"), a single circuit 500 kv transmission line from the Palo Verde Switchyard (40 miles east of Phoenix) to Miguel Substation (10 miles southwest of San Diego).

8. During 1978 and 1979, contemporaneously with its commitment to undertake construction of the SWPL, SDG&E negotiated contracts with TEP and PNM providing long-term commitments for the interstate wholesale sale by TEP and

PNM, and the purchase by SDG&E, of firm electric power for transmission over the SWPL.

9. The TEP contract was entered November 29, 1978 between SDG&E and Tucson Gas & Electric Company ("Tucson," later the Tucson Electric Power Company ("TEP")). It covered sale of electric power by Tucson to SDG&E for a 10-year period commencing March 1, 1979, through December 31, 1988 (subsequently extended to May 31, 1989), during which SDG&E was obligated to pay for specified quantities of firm electric power from Tucson at rates (comprised of a "demand charge" and an "energy charge") specified in the agreement. The specified quantities of power varied from 100 MW to 500 MW over the 10-year period. The contract was divided into five sequential periods, or "phases."

10. The TEP contract, as a contract for the wholesale sale of electric power in interstate commerce, is subject to the exclusive jurisdiction of FERC. On December 5, 1978, it was filed with FERC by Tucson. Following public notice in the Federal Register, FERC, on February 28, 1979, accepted the first two phases for filing. On Application for Rehearing, made on the ground that the five phases of the agreement were one inseparable undertaking, FERC, on June 25, 1979, accepted phases three, four and five of the TEP agreement for filing, subject to certain conditions.

11. The TEP contract has been amended on five separate occasions. Each amendment was submitted to FERC,

and after public notice by publication in the Federal Register, accepted by FERC for filing.

12. Amendment 3 to the TEP contract, among other things, modified the contract to allow TEP to assign the contract to a wholly owned subsidiary without SDG&E's written consent. On June 1, 1984, TEP assigned the contract to Alamito Company, TEP's subsidiary. On October 1, 1984, FERC approved the assignment. Alamito subsequently became an independent company.

13. Amendment 4 to the contract provided, among other things, that Alamito's capitalization ratio, for purposes of calculating the cost of service used in determining the demand charges under the contract, would be 30% equity and 70% debt. In accepting Amendment 4 for filing on July 5, 1985, FERC determined that the proposed rates based on the new capitalization structure would not "produce excessive revenues." On September 11, 1986, FERC again ruled that the rates under Amendment 4 were reasonable, and dismissed a complaint filed by SDG&E, which had contended that Alamito's actual capitalization ratios had produced excessive revenue to Alamito.

14. On November 5, 1985, PNM and SDG&E entered a contract imposing obligations on SDG&E, beginning May 1, 1988 and extending for 13 years until April 30, 2001, to pay for 100 MW of power at rates (comprised of a "demand charge" and an "energy charge") fixed by the contract. The 1985 contract was the successor to the 1979 contract (supra, ¶ 8) between

SDG&E and PNM that had provided for the purchase of power by SDG&E from PNM through April 30, 1988.

15. Like the TEP contract, the 1985 PNM contract is a contract for the wholesale sale of electric power in interstate commerce, and as such is subject to the exclusive jurisdiction of FERC. On June 13, 1988, after public notice by publication in the Federal Register, FERC accepted the 1985 PNM contract for filing.

16. On December 20, 1985, only 18 months after the SWPL was placed in commercial operation with CPUC's approval, CPUC entered its Decision 85-12-108 in SDG&E's general rate case. In that decision (as modified by Decision 86-06-026), CPUC determined that SDG&E's use of SWPL to transmit firm energy pursuant to the TEP and 1979 PNM contracts was not "cost effective." Id. at 120b. CPUC acknowledged that "[w]hen these contracts were signed in the late 1970s and early 1980s, they appeared to be cost-effective" and that "the Commission * * * granted SDG&E a certificate for the SWPL in part because the Commission found that the expected savings under the PNM and TEP agreements would offset the cost of the line." Ibid. However, CPUC concluded that SDG&E had a "continuing obligation * * * to minimize costs" under its contracts for purchases of electricity over SWPL, and ruled that it would review SDG&E's costs under those contracts to determine whether they were reasonable and should be passed on in SDG&E's retail rates. Ibid.

17. CPUC ordered that this "reasonableness" review be conducted as part of SDG&E's 1986 "ECAC" (Energy Cost Adjustment Clause) review, and that it cover SDG&E's power purchases over the SWPL, including those under the TEP and PNM contracts, during the period 1984-1986. The ECAC procedure is one of the means by which SDG&E's retail rates are set. During the year, SDG&E's actual fuel and purchased power expenses are recorded, on a monthly basis, in a "balancing account" along with revenues received from rates then in force. If expenses exceed revenues, an undercollection balance is recorded; if revenues exceed expenses, an overcollection balance is recorded. At each annual ECAC review, the cumulative over- or undercollection balance, together with a 12-month forecast of fuel and purchased power expenses, is used to determine the level of electric rates for the next year. If CPUC determines that certain expenses were incurred unreasonably, those expenses are disallowed from the ECAC balancing account, which results in the expenses being unrecoverable through retail rates.

18. In Decision 85-12-108, CPUC also ordered SDG&E to establish an additional balancing account, called a "SWPL Balancing Account." CPUC ordered that SDG&E's costs for wholesale power purchased over the SWPL in excess of short-term "avoided costs" be recorded in this account. Costs so recorded were to be recoverable in retail rates only when and to the extent that SDG&E reduced SWPL energy costs to less than the CPUC's "avoided costs" standard.

19. On June 4, 1986, CPUC issued Decision 86-06-026 in response to SDG&E's petition for rehearing of Decision 85-12-108. CPUC granted rehearing, limited to six specific issues relating to the SWPL Balancing Account. However, CPUC reaffirmed its determination to review, as part of SDG&E's 1986 ECAC proceedings, SDG&E's costs for purchases over the SWPL during the period 1984-1986. By a subsequent order, CPUC severed the reasonableness review of SDG&E's SWPL purchases from the general 1986 ECAC proceedings, and consolidated that review with the rehearing proceedings on Decision 85-12-108.

20. On February 24, 1989, CPUC issued Decision 89-02-074 in the consolidated rehearing proceedings. In that opinion, CPUC abandoned its requirement that SDG&E establish the SWPL Balancing Account. However, in accordance with the directive in Decision 85-12-108, CPUC carried out a review of SDG&E's costs under its contracts for purchases of power over the SWPL, including the TEP and PNM contracts. Despite its earlier findings that SDG&E acted reasonably in entering into its 1978 and 1979 TEP and PNM contracts in anticipation of SWPL's construction and operation, and despite explicitly ruling that SDG&E's prudence in entering the TEP contract was not at issue in its decision, CPUC concluded that SDG&E had acted imprudently in certain respects in its subsequent negotiations with TEP and in negotiating the 1985 PNM contract. Accordingly, CPUC disallowed portions of SDG&E's costs under those contracts.

21. As to the TEP contract, CPUC concluded that "the level of rates" (Decision 89-02-074, p. 158) in the contract was too high because SDG&E had failed to force Alamito to agree to a more favorable capitalization ratio than that approved by FERC in Amendment 4. CPUC reasoned that had SDG&E retained its right to consent to the assignment of the contract, rather than waiving that right as part of the FERC-approved Amendment 3, it could have used that right as bargaining leverage in its subsequent negotiations with Alamito. CPUC accordingly ruled that $5,928,000, plus interest, of SDG&E's costs under the TEP contract were unreasonable, and should be disallowed. Under CPUC's ruling, SDG&E will not be allowed to recover this amount from its ratepayers, despite FERC's approval of the rates in the TEP contract as "just and reasonable" in the exercise of its exclusive regulatory jurisdiction.

22. As to the 1985 PNM contract, CPUC concluded that SDG&E had failed to "consider and analyze carefully several of the important terms" of the FERC-approved contract, and that it "fail[ed] to react appropriately to changing circumstances and information that affected key terms of the contract." Id. at 96. In particular, CPUC determined that SDG&E acted unreasonably in agreeing to a contract term beginning in 1988, in failing to analyze adequately the market for oil and gas, and in failing to negotiate a lower demand charge under the contract. CPUC asserted that had SDG&E acted differently it might have been able to negotiate a "a better deal" with PNM. Id. at 71.

Accordingly, CPUC concluded that SDG&E had incurred "unreasonable costs" under the contract, amounting to a total of $21,134,000, plus interest, and prohibited SDG&E from recovering this amount in its retail rates. (CPUC also determined that SDG&E had acted imprudently in failing to demand price concessions in exchange for agreeing to a contract modification by PNM, and disallowed an additional $20,000 of its costs under the PNM contract on this ground.)

23. On September 7, 1989, CPUC denied rehearing of its Decision 89-02-074, after modifying its opinion to add additional findings of fact and conclusions of law. On September 27, 1989, CPUC made additional modifications to its opinion. Decision 89-02-074 is the final decision of CPUC and is not subject to reconsideration by CPUC.

FIRST CLAIM FOR RELIEF

(Violation of the Filed Rate Doctrine)

24. Paragraphs 1 through 23 are incorporated by reference.

25. Under the "filed rate" doctrine as reaffirmed by the Supreme Court in *Nantahala Power & Light v. Thornburg*, 476 U.S. 953 (1986), and *Miss. Power & Light v. Miss. ex rel. Moore*, 108 S.Ct. 2428 (1988), FERC's acceptance for filing of a contract for the interstate wholesale sale of electric energy establishes the just and reasonable rate for such power which is binding on the states. "[A] state utility commission setting retail prices must allow, as reasonable operating expenses, costs incurred as a result of paying a

FERC-determined wholesale price." Nantahala, supra, 476 U.S. at 965. The CPUC's decision refusing to allow SDG&E to include in its retail rates, as reasonable operating expenses, the costs it has incurred in purchasing wholesale power in the interstate market from TEP and PNM at rates filed with and accepted as just and reasonable by FERC is preempted by federal law, invades an area that is subject to exclusive federal jurisdiction and violates the Supremacy Clause of the United States Constitution.

SECOND CLAIM FOR RELIEF

(Violation of 42 U.S.C. § 1983)

26. Paragraphs 1 to 25 are incorporated by reference.

27. CPUC's actions deprive SDG&E of rights, privileges and immunities secured by the Constitution and laws of the United States in violation of 42 U.S.C. § 1983.

INJUNCTIVE RELIEF

28. CPUC's order pursuant to Decision 89-02-074 directs SDG&E immediately to reduce its Energy Cost Adjustment Clause ("ECAC") account by the amount of the costs under the TEP and 1985 PNM contracts that CPUC disallowed in that decision. Because only those expenses recorded in the ECAC account are considered in setting retail rates and thus recoverable from ratepayers, the effect of CPUC's order is unlawfully to deny SDG&E the right to recover, as reasonable operating expenses, costs it has incurred in purchasing

wholesale power in the interstate market at FERC-approved rates. Thus, unless this order is enjoined, SDG&E will be irreparably injured, with no adequate remedy at law, by being precluded from recovering its costs under the TEP and 1985 PNM contracts.

29. 16 U.S.C. § 825p confers exclusive jurisdiction on the United States district courts over suits to "enforce any liability or duty created by, or to enjoin any violation of" the Federal Power Act. The actions of CPUC challenged in this case violate the Federal Power Act and are subject to injunction under section 825p.

Wherefore, plaintiff prays for relief as follows:

(a) For a declaration that defendants' order refusing to allow, as reasonable operating expenses, SDG&E's costs for power under its federally filed and accepted just and reasonable rate schedules in its interstate contracts with TEP and PNM is in excess of CPUC's authority and unlawful, and declaring that the rates paid by SDG&E under those contracts are binding on CPUC and are operating costs which SDG&E must be allowed currently to recover from its ratepayers;

(b) For a permanent injunction enjoining defendants, their agents and anyone acting on their behalf from enforcing defendants' order in Decision 89-02-074 disallowing SDG&E's costs under its contracts with TEP and PNM or from taking any other action that would prevent SDG&E from currently recovering from its ratepayers costs incurred under its contracts with TEP and PNM, and requiring them to permit SDG&E to include such costs in, or restore them to, its ECAC account;

(c) For an award of plaintiff's costs of suit and reasonable attorneys' fees herein; and

(d) For such other and further relief as may be just and proper.

Dated: September 29, 1989.

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CODIFICATION OF PIKE COUNTY/REGIONAL BOARD
COMBINED FURTHER REDRAFT OF 7/19/89

(a) Notwithstanding any provision of law, each State regulatory authority has the power to judge the prudence of a purchase of electric energy at wholesale, allocate or deny the inclusion of the cost of such a purchase in rates, and otherwise exercise its functions, for each electric utility company subject to such authority's jurisdiction; **provided**, however, that such power shall not extend to wholesale purchases of electric energy for system supply, or allocations of costs attributable to such purchases, when made by a registered holding company or a subsidiary of a registered holding company which is not an electric utility company.

(b) The prudence of (wholesale purchases of electric energy and the justness and reasonableness of allocations of costs attributable to such purchases) **(ELECTRIC ENERGY SUPPLY ACQUISITIONS AND DEMAND SIDE MEASURES)**[1], when made by a registered holding company or a subsidiary of a registered holding company which is not an electric company, may be regulated by a regional body comprised of representatives from each State regulatory authority exercising jurisdiction over an electric utility company subsidiary of the registered holding company. The jurisdiction of the Federal Energy Regulatory Commission under the Federal Power Act shall not extend to any issue decided by a regional body established under this paragraph.[2] Judicial review of any final order of such a regional body shall be pursuant to section 313 of the Federal Power Act.

GRAY/HARRINGTON/WILLI/DRAFT/JOHNSTON/AMEND

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[1] The clause in bold caps is offered as an alternative to the clause in parentheses in lower case. This alternative would broaden the jurisdiction of the regional body to include regulation of holding company construction and demand-side initiatives in addition to power purchases; however, the alternative would only apply to such activities conducted on a "system basis" by the holding company itself or a subsidiary which is not a State-regulated utility operating company.

[2] As an alternative, the FERC could be provided appellate jurisdiction to review the decisions of the regional body pursuant to the standards applied to FERC decisions by the U.S. Courts of Appeals, i.e. those provided by the Administrative Procedures Act.

DRAFT OF 9/12/89

OUTLINE OF PROPOSED PROCEDURES FOR REGULATION OF MULTI-STATE UTILITY POWER PURCHASES BY REGIONAL BOARDS

A. Introduction: The following outline provides a procedural schedule for the regulation of wholesale power purchases by a regional regulatory body comprised of State regulators from the States in which a multi-state holding company operates its distribution affiliates. The outline is intended to implement provision 4 of the Resolution adopted by the NARUC on July 27, 1989 concerning reform of the Public Utility Holding Company Act.

In the context of wholesale purchases by a holding company, there are essentially three things to be regulated: 1. The justness and reasonableness of the power sale by the supplier (the J & R issue); 2. The prudence of the purchaser in light of alternative sources of supply (the Pike County issue); and 3. If the purchase is for "system supply", the just and reasonableness of the allocation of the purchase among the operating company subsidiaries of the holding company (the allocation issue). The outline describes how each of these issues would be treated by either the Federal Energy Regulatory Commission (FERC) under the Federal Power Act (FPA), or by the Regional Regulatory Body (RRB) under legislation authorizing their creation.

B. The Outline:

1. Legislation is enacted which authorizes the formation of RRBs by those States which regulate the operating subsidiaries of multi-state holding companies.

2. Through voluntary action, the States form an RRB, and file a notice with the FERC and the holding company to that effect. FERC retains jurisdiction for those holding company systems for which no RRB is created.

3. The following procedures then apply for wholesale purchases made by a holding company for which an RRB has been established:

a. The holding company identifies a source of supply, negotiates a purchasing agreement with the supplier, and then files a case with the FERC to resolve issues 1-3. The holding company serves its pleadings on each of the State commissions comprising the RRB. In its pleadings, the holding company **states whether the purchase is for "system supply", i.e.** whether the power and purchase costs will be assigned to more than one of its operating subsidiaries.

b. Within 60 days, each of the States comprising the RRB must notify the FERC that either or both issues 2 and 3 will be referred to the RRB. If all of the States do not invoke the RRB on an issue, FERC retains jurisdiction as to that issue. [Time limit for exercise of FERC default jurisdiction?]

c. Initially, the case is handled under normal FERC procedures: suspension by the FERC, possible referral to an FERC Administrative Law Judge under standard FERC practice, and if so referred, hearing and an ALJ decision which addresses all three of the issues. [Time limit for ALJ consideration?]

d. Review of the ALJ's decision or FERC suspension order is conducted in phases. Issue one is decided by FERC under normal FPA procedures, including rehearing. [FERC could be required to reach its decision on issue one within 180 days of the issuance of the ALJ's initial decision and its decision on rehearing within 90 days.] FERC would be free to apply whatever lawful standards, such as a "market power" test, to its resolution of the J & R issue. Once the FERC has finally determined that the sale is just and reasonable, the RRB then has 275 [180] days to decide issues two and three.

e. The decisions of FERC and the RRB are then appealable as a single decision under normal FPA procedures.

4. Once judicial remedies have been exhausted, the combined decisions of the FERC and the RRB are binding (as in Mississippi Power and Light) on each of the State commissions regulating one or more of the holding company's operating subsidiaries.

C. If the RRB process breaks down (e.g. if the State members of the RRB cannot reach unanimity on issues 2 or 3), all jurisdiction defaults to the FERC regardless of the stage of the proceeding. [FERC shall decide either or both issues within 270 (180) days, with no more than 90 days for final determination on rehearing.]

D. It is important to note that these procedures would apply only for wholesale purchases made by a multi-state holding company through an entity other than one of its operating subsidiaries. Purchase made at the operating company level to meet that subsidiary's own need for power, regardless of the source, would remain subject to the jurisdiction of the State commission (with respect to issues 2 and 3) regulating the retail rates of the subsidiary.

ENVIRONMENTAL ACTION
FOUNDATION

January 19, 1990

William Conway, Esq.
Senior Counsel
Committee on Energy and Natural Resources
U.S. Senate
Washington, DC 20510

Dear Bill:

I hereby enclose my answers to the questions of Sen. McClure, following the hearing of Nov. 16, 1989. By agreement with your office, these answers are due today.

Thank you for providing me the opportunity to participate in the hearing. If you have any questions, please do not hesitate to call.

Sincerely,

Scott Hempling
Attorney

1525 New Hampshire Ave., N.W. • Washington, D.C. 20036 • (202) 745-4870

I. Do you support Printed Amendment No. 267 as introduced? If not, what changes would be necessary to secure your support? Please provide the Committee with the statutory language which you would propose to be added.

A. I do not support PA 267 as introduced. The stated goal of the drafters is to increase wholesale competition in the electric markets. As a representative of retail ratepayer interests, I agree with that goal. Vigorous wholesale competition is a proven means of disciplining retail electric monopolies to produce power efficiently and inexpensively.

B. PA 267 will produce the opposite result. To encourage more competition, one must answer two questions: (1) Who should enter bulk power markets? (2) Under what entry rules? PA 267 answers these questions as follows: (1) Everyone. (2) No rules. PA 267 makes no attempt to determine the rudimentary components of a competitive wholesale electric market, and to ensure that those components exist. Instead, PA 267 eliminates all significant PUHCA protections, including provisions which protect competition. To appreciate the harm produced by a blanket elimination of the PUHCA protections, one must examine the PUHCA provisions one by one, retaining those that protect consumers, adjusting those that do not. PA 267 reflects no such analysis. In the name of competition, PA 267 repeals pro-competitive provisions.

C. Because PA 267 uses the wrong vehicle and leads in the wrong direction, it cannot be corrected easily by amendment. Rather than eliminating the key provisions of the Holding Company Act, which is what PA 267 does, we should review each provision. Those provisions which assist competition should remain; those that do not should be adjusted. And where the combination of existing statutes leaves gaps in consumer protection, we must fill those gaps. The resulting legislation should accomplish the following goals:

1. Entities seeking to enter wholesale markets must demonstrate, in advance, their permanent inability to obtain or exercise market influence.

2. Congress should consider a carefully targeted adjustment to the "integration" requirement of the Act.

3. Existing utilities should not be permitted to expand from their base as retail and transmission monopolists until Congress verifies their inability to compete unfairly.

4. FERC must have the authority and the duty to order nondiscriminatory transmission access, on behalf of both existing and new participants in wholesale markets, where necessary to promote or protect the forces of competition.

5. Competitors, consumers and regulators must have expedited access to regulatory procedures and protections if the

conditions warranting initial entry change adversely.

6. The relationship between federal regulation and state regulation must be rational, predictable; utilities should not be able to use corporate form or transactional form to shift regulatory locus.

7. Congress must confirm the legal standing of retail and wholesale customers, and of competitors, to challenge agency decisions adverse to wholesale competition.

D. In several of my answers below, I offer specific language to attain some of these goals.

II. Would you support PA 267 if the recommendations of the National Association of Regulatory Commissioners are added?

A. The NARUC recommendations properly express a concern that absent a clear division of authority between state and federal regulators, utilities can create wholesale affiliates under PA 267 as a means of "forum shopping" between state and federal jurisdictions. I agree with that concern.

B. More work is necessary to translate the NARUC recommendations into clear legislative language. The NARUC recommendations express a general preference to preserve state jurisdiction, but do not make clear precisely who would regulate the following types of transactions, each of which is, or easily can become, common in the electric industry:

1. Purchases by A Utility Who Is Not a Member of a Centrally Planned Holding Company System, and Is Not a Member of a Centrally Planned Pool of Unaffiliated Utilities

   a. Buyer (B), not a member of a centrally planned holding company system, buys from Seller (S), a nonaffiliated entity

   b. B, not a member of a centrally planned holding company system, buys from S, an affiliated entity

2. Purchases by A Utility Who Is a Member of a Centrally Planned Holding Company System

   a. B, a member of a centrally planned holding company system, buys from S, a nonaffiliated entity, for system supply

   b. B, a member of a centrally planned holding company system, buys from S, a nonaffiliated entity, but not for system supply

   c. B, a member of a centrally planned holding company system, buys from S, an affiliated entity, for system supply

d. B, a member of a centrally planned holding company system, buys from S, an affiliated entity, but not for system supply

3. Purchases by A Utility Who Is a Member of a Centrally Planned Pool of Unaffiliated Utilities

    a. B, a member of a centrally planned pool of unaffiliated utilities, buys from S, an unaffiliated entity who is a member of the pool

    b. B, a member of a centrally planned pool of unaffiliated utilities, buys from S, an affiliate who is a member of the pool

    c. B, a member of a centrally planned pool of unaffiliated utilities, buys from S, an affiliate who is not a member of the pool

    d. B, a member of a centrally planned pool of unaffiliated utilities, buys from S, an unaffiliated entity who is not a member of the pool

C. Moreover, the NARUC recommendations deal only with one aspect of the electric industry debate: the need to restore predictability to the state-federal regulatory relationship. The NARUC recommendations do not claim to solve the anticompetitive problems created by PA 267. They provide advance protection against self-dealing or diversification, and they restore none of the Holding Company Act protections which PA 267 would repeal. As a result, enacting PA 267 with the NARUC recommendations still would leave consumers at risk.

III. Would you support PA 267 if a transmission access or mandatory wheeling provision is added?

A. A wholesale transmission access provision, properly enforced, is necessary to reduce risks to competition created by PA 267. The legislative objective should be to lodge, in some administrative authority, the unambiguous duty to order the nondiscriminatory, cost-based sharing of transmission facilities where access to such facilities would protect or promote fair competition. An example of such language is as follows:

> "FERC shall order the owner of transmission facilities to offer transmission services on terms which are nondiscriminatory, just and reasonable, to any wholesale purchaser or wholesale seller of electricity in interstate commerce, where the failure of the owner to offer such transmission services is unjust or unreasonable, discriminatory or anticompetitive."

B. Some additional language would be necessary to give guidance on, and prevent future litigation over, the meaning of the terms "unjust or unreasonable, discriminatory or anticompetitive" in the context of transmission pricing and acccess; to give FERC an initial period of time during which it would asssess each transmission owner's market position to determine if existing practices are unjust, unreasonable, discriminatory or anticompetitive; and to provide a complaint procedure by which refusals to offer transmission services could be resolved expeditiously and inexpensively, before irreparable harm to competition occurred.

C. Unless Congress makes this clear delegation of authority, victims of transmission discrimination have only three options: (1) suing in U.S. District Court under the antitrust laws; (2) receding to the transmission owner's anticompetitive demands; or (3) doing without transmission access. Each of these options is inconsistent with the type of fair commercial relations on which normal businesses depend for success. For example, antitrust litigation takes many years and many millions of dollars. That forum simply is not available to competitors lacking large upfront resources, and it is not available to those whose projects require transmission access now, not 5-10 years from now. Where the only forum is antitrust litigation, competitors face a "Catch 22": they cannot get financing for their projects without transmission, and they cannot litigate over transmission without financing. The result is that small competitors cannot enter the industry; only established utilities with market power would remain. That result is the opposite of the goals stated by the supporters of PA 267.

D. Some have said that the transmission debate is "too complex" for Congress and that, therefore, the debate must take place at FERC. That argument makes no sense if FERC lacks the statutory authority to implement the proper solutions. Many utilities tell Congress that FERC should handle transmission, and then tell FERC that FERC lacks authority to order transmission. Those positions are inconsistent. My suggested language prevents that inconsistency.

E. Whether the duty to order transmission access should lodge in FERC or in state commissions is a separate issue. I do not intend that my proposal to grant FERC clear authority be interpreted as opposing state authority over some types of transmission transactions. I focus on FERC because many important transactions, or potential transactions, cross state lines; and the only possible entity to regulate such transactions is FERC. It is possible that for certain transactions, state regulation may be the right approach. But the duty must exist somewhere.

F. Abuse of the transmission monopoly is not the only way to exercise market power or to harm consumers. PA 267 opens up other doors, such as self-dealing and cross-subsidization. Therefore, the language I have proposed would not improve PA 267 sufficiently to warrant the risks created by the bill.

IV. PUHCA was enacted to address very serious problems caused by utility holding companies. Is the current absence of abuses evidence that PUHCA has outlived its usefulness, or proof that it continues to work effectively?

A. This question contains a premise with which I respectfullly disagree: that there is a current absence of abuses. There is a strong pattern of abuses in the industry today that have gone unpublicized. This pattern makes clear that those abuses arise where PUHCA is not operative, or where it is operative but not enforced. From these examples, one must infer that the Act must remain in place to protect consumers and competition.

B. The most pervasive abuses exist where PUHCA does not apply: when utilities create PURPA affiliates and buy power back from those affiliates.

1. The creation by a utility of an affiliate, followed by the utility's purchase of electricity from that affiliate to serve the utility's own retail load, is a relatively recent phenomenon. Until 1978, a utility could not create or acquire more than one such affiliate without first satisfying the "advance review" tests of PUHCA. Sections 9 and 10 of PUHCA, 15 U.S.C. sec. 79i and 79j, required the utility to make an affirmative showing to the U.S. Securities and Exchange Commission ("SEC") that the acquisition (1) would produce economies and efficiencies for the utility's ratepayers by "integrating" the acquired assets with the utility's existing assets, (2) would not create the potential for anticompetitive behavior, and (3) would not result in corporate structures that complicate state regulation. These tests effectively barred a utility from creating an affiliate to supply power that the utility could supply itself.

2. In 1978, this statutory scheme changed dramatically. The Public Utility Regulatory Policies Act of 1978 ("PURPA") created a category of generating utilities known as "qualifying facilities." Pursuant to Congressional authorization, the Federal Energy Regulatory Commission ("FERC") then excepted these entities from PUHCA on a blanket basis. FERC also permitted traditional utilities to own up to 50% of any qualifying facility. Due to this blanket exception, a traditional utility now may create or acquire an unlimited number of generating utilities without satisfying the advance review tests of PUHCA, provided the generating utilities are "qualifying facilities" under PURPA.

3. Since the enactment of PURPA, many traditional utilities have created PURPA affiliates, and then purchased power from those affiliates at prices higher than the cost the utility would have incurred had the utility produced the power itself. The transactions between utilities and their affiliates, unmonitored by the SEC under PUHCA, have engendered much controversy and years of litigation,

particularly in California and Michigan.

4. The Appendix to my prepared testimony describes these abuses in detail.

C. The second type of abuse takes place where PUHCA operates but is not enforced. The best example is the failure of the savings and loan association owned by Pinnacle West, an exempt holding company which also owns Arizona Public Service.

1. Merabank's failure has pushed Pinnacle close to bankruptcy. Investors and federal savings and loan regulators will require Pinnacle to pledge Arizona Public Service's utility assets as collateral for a loan designed to save the failing bank. This arrangement makes explicit what consumers always feared: that they are directly at risk for the failure of diversification.

2. Merabank is an "exempt" holding company. Under Section 3 of the Act, the SEC is obligated to revoke an exemption (thus subjecting the holding company to the Act's "registration" requirements, including the nondiversification rule of Section 11(b)(1)) if the exemption becomes "detrimental to the public interest, or the interest of consumers or investors." Where was the SEC during the months and years when Merabank slipped inexorably toward failure, creating a clear "detriment" to consumers? Where is the SEC now, as banks make consumers the insurers of Merabank's success? No one knows the answer to these questions.

D. There is a tendency in some states to say "we don't have holding company problems, so we are not concerned about the debate over PUHCA." Like fluoridation of the water supplies, the Holding Company Act protects silently.

V. What impact would PA 267 have on the structure of the electric industry?

A. Under PUHCA today, the primary suppliers of electric power are engaged exclusively or primarily in the electric business alone. Moreover, they serve single retail service territory; or if there is more than one service territory, these territories are "integrated" electrically and operationally. Finally, most utilities produce and sell power at retail through a single corporation.

B. There are three exceptions to this rule today. First, "exempt" holding companies, primarily those who operate within one state, may diversify into nonutility businesses, under SEC review. ("Registered" holding companies -- mostly interstate systems -- may not diversify.) Second, some registered holding companies, like Entergy, have moved their generation from the retail subsidiary to a wholesale corporation. Third, utilities who own

PURPA projects have placed them in separate subsidiaries and buy at wholesale.

C. Under PA 267, the industry structure can change dramatically. This is because PA 267 repeals three types of PUHCA provisions, as applied to wholesale generators. These provisions (1) prohibit non-integrated holding companies, (2) prohibit diversification by multistate companies and (3) require a pre-acquisition check for acquisitions that are anticompetitive. As a result, the new entrants into the industry can include construction contractors like Bechtel and Westinghouse; stock traders with excess cash, like Carl Icahn or Donald Trump; and foreign corporations; as well as existing utilities, both intrastate and interstate. These corporations could enter the market anywhere, acquire as many wholesale utilities as they desire, become controllers of generators and transmission facilities, run worldwide operations in lines of commerce bearing no relationship to electricity, and face no advance review under PUHCA.

D. What is impermissible under PUHCA today -- multistate structures with investments in both utility and nonutility businesses, and the accompanying risks of cross-subsidies among them -- would be permissible under PA 267. There would be no limits on the size, geographic scope, or type of business engaged in by these structures. Due to the unlimited interstate and international nature of these new entities, individual states would be hard-pressed to monitor, let alone detect and ferret out, cross-subsidies and other abuses. "Exempt wholesale generator" would not describe these structures accurately; "exempt diversified business with unlimited investment in wholesale generators, monopoly transmission facilities, and nonutility businesses" would.

VI. What impact would PA 267 have on the price, supply and reliability of electricity?

PA 267, which purports to encourage competition through independent power production, would have the opposite result. By failing to distinguish true independents from utilities and construction contractors, the bill would encourage concentration of electric production in the hands of a few large entities who control major sources of generation, transmission facilities and construction resources. If that is the result, we will have less competition. Consumer prices necessarily will rise, and supplies will be constrained.

VII. A key assumption of PA 267 is that not enough powerplants are now being constructed to meet future power needs. Is that true everywhere, or only in certain states or regions? Do you agree with the assertion made by some that state public utility commissions are primarily to blame for the lack of adequate powerplant construction, or are other factors responsible?

A. As the question correctly points out, some supporters of PA 267 make a connection between repealing Holding Company Act protections and building more power plants. The logical tie between those two points is not inherently obvious. The Holding Company Act concerns the acquisition of new utility subsidiaries by existing entities. How does that subject relate to building more power plants? I believe the logical link goes something like this:

1. The most common corporate form for a utility today is a single corporation; that corporation produces power for retail consumption and is regulated by state commissions.
2. Utilities will not build if they are regulated by state commissions. They will build only if they are regulated by FERC or regulated by no one.
3. PA 267 frees utilities to create generating companies to sell at wholesale. Those generating companies will be regulated by FERC, not states; and FERC may have plans to reduce rate regulation.

B. As this logical link shows, the asserted connection between PA 267 and building more power plants depends on two premises. The first premise is that under PA 267, utilities will be free to avoid state regulation. The second premise is that FERC will stop regulating rates, or will do so less stringently than states.

C. The problem is that supporters of PA 267 deny both premises, thereby calling into question the bill's rationality. They assert that there will be no reduction in state regulation. And they argue that they intend no weakening of FERC regulation. If these two statements are true, then there is no connection between PA 267 and construction of more power plants.

D. With respect to the role of state regulators: Utility statements scoring state regulators for their review of the prudence of power plant construction do not make sense, for at least two reasons.

1. First, utilities assert that state regulators pushed them to build more power plants, and later criticized them for doing so. That assertion is largely untrue or misleading. Many of the ill-fated power plants were urged by utilities; it was not the other way around. And, to the extent state commissions "approved" the construction of power plants in advance, few if any stated that such approval included an advance determination that the decision to build, and the ongoing construction practices, were prudent. The mode of state regulation in the late 1960s and the 1970s was that utilities received permission to build; they did not receive a determination that the decision to build was prudent. In general, the state laws contained nothing that would lead a utility manager to believe that its decision to build, once "approval" was obtained, was a risk-free decision. State

approvals meant "It's up to you," not "Good decision." Indeed, most utilities during their construction periods sought risk premiums in their rates of returns, expressly because of the risks associated with construction, including the regulatory risks. If the state approval were tantamount to an approval of the prudence of the construction decision, there would have been no need for the risk premium. This was the clear import of the U.S. Supreme Court's 1989 decision in Duquesne Power & Light v. Barasch.

2. Second, in every state utilities had the right to judicial review of the state commission decisions, including ultimate review in the U.S. Supreme Court. Many utilities now expressing dissatisfaction with state commission decisions sought judicial review to correct commission errors. Many of these utilities lost; some won. Therefore, an indictment of state commissions necessarily is an indictment of the state court systems as well, and of the state statutes under which all of these cases were litigated. Any large investment decision, particularly those involving cost overruns, will create a litigated dispute. The issue is not whether utilities are dissatisfied with the outcome; the loser in litigation always is. The issue is whether the process was unfair. No utility ever has provided specific evidence of where the process was unfair.

VIII. What are your views on allowing utility-owned EWGs to sell power to their utility parents?

A. I oppose allowing utility-owned EWGs to sell power to their utility parents. Such sales are inconsistent with the utility's franchise obligation, and lead to serious abuses. Specifically:

B. Utility Purchases From Affiliates, For the Purpose of Serving Captive Customers, are Fundamentally Inconsistent With the Utility's Obligation to Serve at Least Feasible Cost: Assume a new low-cost generation opportunity appears. The parent utility with the retail monopoly should exploit this opportunity for its customers. Instead, the utility channels the opportunity to its affiliate. The affiliate then produces the low-cost power, and sells to the parent utility at the parent's higher avoided cost. Captive retail customers would pay that marked-up price. In effect, the utility would have diverted savings from captive customers to shareholders. That behavior violates the monopoly franchise obligation.

1. The parent utility also would have violated principles of fair competition. In a free market, competition would push the retail price down to the level of the most efficient seller's production cost. But in the case of a franchised utility, where there is no competition at retail, the price remains at the utility's avoided cost. The difference is monopoly rent. Prices reflecting monopoly rent are

inefficient, legally exploitative, and violative of antitrust law.

2. The idea of a utility-owned EWG "selling" to its parent is a legal fiction. In effect, there has been no "sale" from the affiliate to the utility parent. Instead, the utility parent has raised its price to its captive customers, above the price which would have existed had fair competition prevailed.

C. Utility Affiliates Can Become Instruments of Self-Dealing: Abusive self-dealing occurs when the customers of the monopoly utility pay a supramarket price for a service or good supplied by an affiliate because there was no unaffiliated competitor to provide the service or good. Conversely, abusive self-dealing occurs when the utility transfers assets or provides services to the affiliate at a below-market price.

1. The utility affiliate relationships spawned by PURPA have led to serious self-dealing abuses, as shown by Appendix A of my Committee testimony of Nov. 16, 1989. PA 267 would expand the potential for self-dealing dramatically, in at least two ways. First, PA 267 permits utilities conduct without restriction the self-dealing now permitted in PURPA facilities only.

2. Second, PA 267 directly eliminates existing protections against self-dealing. Under PA 267, an "exempt wholesale generator" is deemed not to be an "electric utility" under PUHCA. A utility can therefore acquire unlimited numbers of EWGs in many states. Under PUHCA today, a holding company with wholesale utility subsidiaries spread across several states would be a registered holding company, like Entergy or American Electric Power. Under today's Act, a registered holding company would be subject to the interaffiliate transaction monitoring under Sections 13, 14 and 15 of the Act. But since the entity owning EWGs would not be a registered holding company (it would not be a "holding company" at all because it owns no "electric utility"), the entity would not be subject to Sections 13, 14 and 15. In short, an entity whose self-dealing would be monitored under today's Act would not be monitored under PA 267. The difference is stark.

IX. What are your expectations about how FERC will regulate EWGs? Do you expect that FERC will engage in traditional cost of service regulation, or will it instead allow EWGs to charge "market prices," as has been the direction FERC has recently been heading through a number of case-specific decisions?

A. In several decisions, FERC has strayed from the cost-based principles of the Federal Power Act and the underlying case law. Cost-based pricing and so-called "market pricing" should reach the same result. Market pricing makes sense only when there is a permanent, vigorous market. A permanent, vigorous market can exist only when there is a large number of players, and when all those players have nondiscriminatory access to essential resources, including financing and transmission facilities.

B. Very few electric wholesale markets have these characteristics. Until they do, market-based pricing is unregulated pricing; and it is an unreliable method for protecting consumers.

C. Because the membership at FERC changes so frequently, it is difficult to predict future FERC decisions.

X. Would EWGs be "fuel neutral"?

A. The answer depends on many factors. Under the bill as drafted, those with large resources, including preferred access to transmission, financing and construction services, are likely to prevail competitively over smaller companies in the competition to provide new power supplies. Some believe that if the market is biased toward the large established entities, the resulting EWGs will build large plants that emphasize coal and nuclear fuels; whereas smaller companies, who are required to substitute skill and efficiency for large financial resources, will seek more efficient power supply solutions. This bias toward large construction is made more likely if power suppliers are free to shift between state and federal regulatory forums, depending on which gives more favorable regulatory treatment.

B. If, on the other hand, legislation passes which ensures fair competition, including nondiscriminatory access to transmission, financing and construction contractors, and which ensures a premier role for state commissions in the selection of power supply alternatives, the winners are likely to be use more efficient supply solutions.

C. What will the "more efficient supply solutions" be? The answer to that question depends on predictions of fuel prices and conservation costs long into the future. Since such predictions are difficult to make and defend, the best policy now is to pass legislation that ensures that at each decisionmaking point, the most efficient solution can prevail. PA 267, by repealing essential protections of competition, will not have that effect.

XI. One key issue in the PUHCA reform debate is whether IPPs would have an artificial advantage over utility powerplants due to the tax benefits of debt leveraging. A Committee staff analysis concludes that debt leveraging does not create an unfair advantage for IPPs. What are your views?

A. I am following the technical debate over the effects of debt leveraging and do not yet have a position on the issue of fairness or unfairness. I would insert into that debate the following thoughts.

B. Leveraging is not a free lunch. The higher the debt ratio, the greater the fears of investors -- both stockholders and bondholders -- that the entity lacks sufficient assets to pay dividends consistently, or retire the debt principal, during times of economic downturn. Owners of securities in the buying utility will be concerned that if the affiliate encounters financial difficulty, the holding company parent will shift assets or funds from the utility to the affiliate, thereby weakening the utility. The utility's equity owners will demand some protection for that risk, in the form of higher returns. The money for those higher returns comes from captive ratepayers.

C. If leveraging were indisputably beneficial to consumers, utilities would leverage, and there would be no justification for the affiliate. But many states and their regulators are risk averse, and do not want the utility to leverage. Under these circumstances, a utility who proceeds to create a leveraged affiliate and then buy power from that affiliate is circumvent the state's bar on leveraging.

D. In response, utilities argue that when leveraging occurs in the affiliate rather than the utility, the corporate boundary between the two entities insulates the ratepayer from risk. But substantial elements on Wall Street disagree. They will downgrade the bond ratings of the utility when there is a substantially leveraged affiliate in the corporate structure. To these financial analysts, risk does not stop at corporate boundaries. Under these circumstances, the ratepayer pays for the risk.

E. The worst situation occurs when the utility creates a leveraged affiliate, and buys power from the affiliate at a price reflecting not the affiliate's lower cost, but the cost of the utility's next most expensive option. None of the savings from leveraging (due to the lower capital costs associated with debt) would go to ratepayers. Ratepayers would bear the risks of leveraging but get none of the benefits; and the utility would have circumvented state restrictions on leveraging to boot.

APPENDIX II

Additional Material Submitted for the Record

STATEMENT OF POSITION ON PROPOSED LEGISLATION TO AMEND THE PUBLIC UTILITY HOLDING COMPANY ACT

on behalf of the

SOUTH CAROLINA DEPARTMENT OF CONSUMER AFFAIRS
and
NATIONAL ASSOCIATION OF STATE UTILITY CONSUMER ADVOCATES

by

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before the

Committee on Energy and Natural Resources
United States Senate
Room SD366

November 16, 1989

OVERVIEW

As South Carolina Consumer Advocacy Division Director, Chairman of the Electric Committee of the National Association of State Utility Consumer Advocates (NASUCA), and a member of its Executive Committee, I am pleased to address you today on proposed amendments to the Public Utility Holding Company Act of 1935 (PUHCA). NASUCA is an organization composed of members from 40 states and the District of Columbia. The members of NASUCA, like the South Carolina Department of Consumer Affairs, are designated by State law to represent consumer interests in utility matters in state and federal regulatory agencies and courts.

As you are aware, a primary goal of Congress in enacting PUHCA was protecting and maximizing the consumer welfare. In an effort to develop a sense of our members' views on the necessity of maintaining PUHCA protections in the face of growing electric competition, the NASUCA Electric Committee asked members to respond to a PUHCA survey. I have attached a Summary of Responses from NASUCA members. The responses reflect a recognition that what is really at stake is the future structure of the electric and gas industry, as well as a wariness that more abuses in least cost utility planning, transmission access, retail wheeling, and self-dealing will likely result unless the debate itself is structured properly. The purpose of this statement is to address each of these concerns in an attempt to aid this Committee in its deliberations.

STRUCTURE OF THE PUHCA DEBATE

The recognition by NASUCA members that the future structure of the electric and gas industry is at stake when considering changes to PUHCA clearly suggests that the PUHCA debate, itself, must of necessity be structured in a manner to account for this. Specific abuses mentioned below suggest that even the current version of PUHCA does not stop all problems. Moreover, they demonstrate that the consumer welfare must not be allowed to suffer from any PUHCA or for that matter transmission access changes for that matter. Otherwise, if utilities are allowed to spin off affiliated power producers, the companies may well extract monopoly rent, cherry-pick large retail customers, and leave stranded investment. Selective competition is not real competition.

A proper framework for the PUHCA debate, then, will reveal the complexity and interrelationship of a multitude of electric and gas utility issues that arise at both the wholesale and retail levels and, hopefully, a fair and equitable solution. Among the considerations for public policy analysis of competition and regulation are the following ten criteria. They have been developed by utilities and consumer advocates (including regulators) and are appropriate criteria for consideration of regulatory and legislative reforms in the face of competition and adaptations that the industry itself may make. They are:

(1) economic efficiency;

(2) economies of scale;

(3) monopoly power, including antitrust implications;

(4) the ability of regulated utilities to respond to competition;

(5) capital intensity;

(6) quality of service;

(7) equitable treatment, including ability to pay and avoidance of rate shock;

(8) transitional costs and benefits;

(9) national security; and

(10) least cost planning commitments, obligations, and opportunities.[1]

Apply these when analyzing proposed PUHCA and other legislative actions and when shaping public policy.

INTERRELATIONSHIP BETWEEN LEAST COST UTILITY PLANNING AND THE PUHCA DEBATE

The construction cycle of many utilities has ended and they are looking for ways in which to spend and invest their cash. One way is to diversify into utility-related projects, such as independent power producers or Qualifying Facilities projects. In making their decisions on how to commit their money, utilities likely will focus on their notion of economic efficiency and define it to include PUHCA as a barrier to allow efficient entry into the non-utility generating sector.

New sources of generation, of course, are supply-side options. In integrated least cost planning efforts underway across the country more explicit consideration is being given to supply-side options and demand-side options, such as conservation, while the financial stability of utilities is likewise given attention.

Certain utilities may also slow down these LCUP efforts underway in various States. Such an attempt is shortsighted, however. Utilities generally enjoy adequate reserve margins now, and may, therefore prefer not to undertake serious least cost planning efforts. They also figure that some non-utility generators will thereby disappear if they forestall making construction commitments. Some probably will.

Typically, then, some utilities will attempt to shift the burden of proof on PUHCA reform. They will often complain about PUHCA and obscure the transmission barriers. They do not explain how amendment to PUHCA would or could open the door to greater abuses. Furthermore, they have attempted to develop the importance for change in national energy policy by offering proposals, such as the Edison Electric Institute amendment last year and the Johnston bill this year. As the NASUCA survey results show, the majority of survey participants remains unconvinced that PUHCA changes are warranted at this time.

In the aftermath of the U.S. Supreme Court Mississippi Power and Light decision[2], State integrated least cost planning still has a role to play, as well as regional integrated least cost planning. Utilities ought to focus on improving the efficiency and maximizing the consumer welfare of their existing service territories in order to implement a least cost planning approach rather than worry about spending their extra dollars in someone else's service territory or even their own as a non-utility generator. Utilities will argue that rate base regulation constrains them. By that, they mean it constrains their potential profits.

Because of this underlying need to encourage and stimulate least cost planning in a responsible manner by utilizing demand-side and supply-side options, it may well be, if PUHCA were amended, that neither true independents nor utility affiliates should be completely exempt from PUHCA requirements. However, NASUCA is not yet convinced that amendments to weaken PUHCA are necessary or appropriate. In fact, more financial disclosure may be appropriate if there is to be less rate regulation. Proponents for reform must provide convincing evidence that PUHCA reform is required in order to stimulate greater efficiency and competition and to maximize the consumer welfare, thereby shaping the future structure of the electric industry in a responsible manner. Similarly, since gas may increasingly serve as the fuel source for the generation of electricity, the growth of gas transmission and distribution lines, as well as transportation and other gas pricing regimes, will need to be monitored closely. Proponents for PUHCA changes should also address this aspect of expansion planning.

LINKING TRANSMISSION ACCESS WITH PROPOSED PUHCA CHANGES

Some utilities like to say they are disadvantaged under PUHCA. This, however, is generally not the case. Having a franchise, a service territory, and transmission line ownership are advantages, not disadvantages. They often simply want their affiliates to become "independent" power producers.

Certain players, anxious to be participants in the PUHCA debate, link transmission access, pricing, siting, and certification to it. This, in itself, is not wrong. After all, the underlying problem is one of discriminatory denial of transmission access. Many believe that this problem is too thorny to resolve now. Their answer is to go about changing only PUHCA in hopes, perhaps, that this transmission access issue will take care of itself as the generation sector grows more "competitive." However, how truly competitive can the industry become--at least the electric industry--if this issue is not addressed directly, probably through amendment to the Federal Power Act? Not very--and only selectively--at best. The harder question is whether or not "true independents" would be allowed any meaningful entry unless the transmission access matter is addressed and resolved. Why, then, put the cart before the horse?

The overriding reason appears to be to allow only selective competition which, in turn, maximizes monopoly profits in the name of removing PUHCA barriers and promoting competition. However, without adequate transmission access, any real competition among franchised utilities and even true independent non-utility generators stands an unnecessary risk of being short-lived.

On the other hand, when analyzing the need for PUHCA changes from a structural context, one readily realizes that a utility's supply-side options may well be enhanced through wheeling arrangements in lieu of construction of new generation sources. Whereas the utility's (and retail customers') options for generation will be affected if PUHCA is altered, so, too, will they be affected in a potentially more meaningful manner once transmission access is properly linked to the PUHCA debate.

The proponents for change should bear the burden in the transmission access area as well. It appears, however, that once the structural debate approach is followed, different types of players may, perhaps, become advocates for change in either PUHCA, transmission access, or both. Time and perhaps this Committee's willingness to accept substantive amendments to the Johnston bill will tell.

POTENTIAL FOR RETAIL WHEELING

Over the past year I have cautioned audiences that the PUHCA debate, driven by increasing generation sector competition is a structural debate and as such, the potential for retailing wheeling (or bypass) necessarily must be explored as part of it.[3] I caution you as well. Others are beginning to discuss it, too.

In recent remarks at an Edison Electric Institute Financial Conference, FERC Commissioner Charles Trabandt applauded the FERC Staff report on transmission for agreeing that stranded investment and free rider issues need to be addressed. However, he also noted the following:

> The critical comment concerns retail wheeling. The Report states that the Task Force, if not everyone else involved in the transmission debate, sees transmission access in terms of wholesale customers, so-called supplier access, not retail customers obtaining access, or customer bypass. While I have no doubt about the intention, I think the execution falls short. A utility must give transmission to other utilities, including municipalities -- what Utah called transmission dependent utilities, or TDUs -- with no excuse for refusing, short of having already eliminated its off-system sales.
>
> The Report itself admits -- and points to a current case -- that large industrial customers could easily induce a town to take over the local distribution system and create a new municipal utility. Therefore, large industrial customers can now create TDUs to enable these big customers to leave the systems of their local utilities. Since bypass never appeared, even on the gas side, as possible for residential customers, the Task Force has unleashed customer bypass. The Report provides an impetus for a "let a thousand TDUs bloom" movement. Indeed, on rehearing in Utah, we saw that phenomenon. Newly minted municipal utilities, PURPA facilities, IPPS and even industrial customers all wanted in on the short term preference we created for half of Pacificorp's excess transmission capacity. I

> think we decision makers must think about this more thoroughly as well.[4]

Commissioner Trabandt further cautioned that adopting the Staff task force's recommendations "would similarly lead to those kinds of pressures on electric utilities across the country, which on a de facto basis would be retail wheeling."[5]

Moreover, a non-utility generator spokesperson at the same conference stated his view of the relevance of retail wheeling:

> It must be made clear that any new regime for transmission access is for "supplier access" to bulk power markets; the distribution utilities cannot be jeopardized with even the prospect of retail bypass. As a brief comment, this principle is not merely altruism towards utilities on the part of NUGs (nonutility generators); there is also some self-interest involved. The NUGs financing is in large measure a function of the financial market's assessment of the strength of Power Purchase Agreement held by the NUG. A regime of retail bypass puts the purchasing utility's revenues at some risk, and may chill or impair the financeability of that utility's purchase commitments.[7]

NASUCA does not favor retail wheeling and, perhaps, neither does a majority of the Committee. However, given the structural nature of this PUHCA/transmission debate, the varying potential for retail wheeling must be explored under various scenarios. Perhaps Congress should either prohibit it or otherwise provide rules for its control so that the consumer welfare is maximized. No one can doubt that restricting the debate to the wholesale markets is overly confining, when one reflects that the retail sector is the largest electric sector in the United States and is, therefore, bound to be affected by structural charges in the industry's laws. In the meantime, parties to State bidding proposals, bidding agreements, and utility franchise contracts up for renewal can be expected to negotiate to prohibit, restruct, or otherwise condition potential retail wheeling to mitigate potential changes in laws that increase its likelihood of occurring.

EXACERBATION OF SELF-DEALING AND RELATED ABUSES

It is no accident that PUHCA and the Federal Power Act (FPA) were originally drafted together and were considered jointly in Congressional debates, for the drafters realized that the electric industry's structure would be changed over time following enactment. Consequently, jurisdictional and ratemaking rules and standards were included that affected wholesale, as well as retail, ratemaking, in the generation, distribution, and transmission of electricity.

The current debate should be no different for the reasons previously stated. The PUHCA debate should not in itself determine the direction of the transmission debate or vice versa. As the examples of alleged self-dealing and related abuses below demonstrate, PUHCA, even currently, does not prevent all such abuses. However, they underscore the importance of PHUCA as aiding protection of the consumer welfare, rather than as serving as an obstacle *per se* to competition.

1. Southern Company/Gulf Power Company: capital diversion for improper political campaign contributions and tax evasion (pending, United States v. Gulf Power Company, No. CR 89-412 (N.D.Ga.));

2. SCANA/South Carolina Real Estate Development Corporation: inter-affiliate sales of land allegedly at less than fair market value; sales of land allegedly to third parties at less than fair market value; alleged capital diversion to planned construction projects (pending, SCPSC Docket No. 89-230-E/G);

3. American Electric Power/Indiana and Michigan Electric Company: capital diversion and effective preemption on rate of return for fuel cost transportation costs (SEC File No. 70-7167)

4. Columbia Gas System/Columbia Gas of Ohio: Capital diversion and improper influence of inter-affiliate transactions on gas costs (PUCO Case Nos. 83-135-GA-COI and 84-6-GA-GCK, Opinion and Order, October 8, 1985).

5. American Electric Power/Indiana and Michigan Electric Company: FERC approved agreement for seven states served by AEP to share costs of all high voltage transmission lines whereby the Ohio, Virginia, and West Virginia companies began paying millions of dollars annually to reduce the transmission costs of the Indiana and Michigan companies (AEP Services Corporation, Docket No. ER84-348, Opinion No. 311, 44 FERC ¶61,206 (1988)).

6. Northeast Utilities/Connecticut Light and Power Company: stock spin-off producing separate holding company, Yankee Energy System, Inc., as well as CL&P and Yankee gas whereby Yankee Gas purchased CL&P's gas assets and equipment without showing benefit to consumers (CTDPUC, Docket No. 88-04-28, December 21, 1988).

7. Sierra Pacific Resources/Sierra Pacific Power Company: higher costs of financing to regulated subsidiary from losses in unregulated subsidiaries (NVPSC Docket No. 87-1226 (1987); $2 million receivable kept on books for costs relating to Thousand Springs coal-fired generation project without any benefit, such as time value of money, attributed to SPPC (NVPSC Docket No. 89-516 1989).

NASUCA members surveyed indicated their discomfort with the potential abuses that would be more likely to result if PUHCA were amended to allow even true independent power producers to escape PUHCA provisions. These concerns included greater potential for: cross-subsidization; capital diversion; and undermining least cost planning efforts. Although the Johnston bill, as drafted, does not directly repeal or modify the self-dealing provisions of PUHCA (§§13, 14, and 15), its provisions exacerbate the propensity for self-dealing through wide-open creation of exempt wholesale generators (EWGs). For example, EWGs would not be considered electric utilities, so the §10 pre-acquisition review proviso would not apply. Furthermore, §§13, 14, and 15 would not apply in the situation whereby an EWG was acquired over a multi-state region, since it would not be treated as a registered holding company. NASCUA cannot, therefore, support the Johnston bill.

CONCLUSION

NASUCA respectfully requests that the Committee recognize the benefits from the comprehensive approach followed by the drafters of PUHCA and the FPA and take this opportunity to redirect this PUHCA debate. Any legislation should reflect responsibly the broad scope necessarily involved in attempting to change the structure of the electric and gas utility industry. Promoting EWGs through isolated PUHCA changes will cause more harm than good, especially if transmission access and related issues are ignored. On the other hand, the transmission issues in themselves may be viewed as imposing impediments to greater competition within a least cost utility planning framework and, therefore, could be addressed prior to any PUHCA proposals.

Fundamentally, the question for many interested parties is whether or not even "true independents" should be allowed to generate electricity without being subjected to the requirement of PUHCA. If the answer is no, will they eventually enter anyway into the market? If this answer is yes, how should they be allowed entry? Should PUHCA be amended or should the FPA or PURPA be amended? Or should all three be amended? Once again, I believe that the proponents for change to PUHCA should bear the burden, or have the opportunity, to demonstrate why PUHCA, in itself, needs to be amended to effectuate their entry into the marketplace. Why not require them to be subject to PUHCA requirements? Some may argue that the §10(c)(2) "integrated system" requirement would limit their development. This is not an insurmountable problem in itself. Perhaps PURPA could be amended to extend the "integrated system" requirement to include a clarifying provision that so long as the project would contribute to the integration of any system, not necessarily its own, that it would be in compliance with PUHCA.

The above discussion and concerns expressed by Commissioner Trabandt and myself regarding the potential for retail wheeling may, at first blush, appear to provide support for separating rather than joining the PUHCA debate with the transmission access debate. However, I believe they, instead, suggest the complexity of the issues involved and point to the need to broaden the scope of the PUHCA debate rather than let the tail wag the dog by explicitly focusing only on the wholesale bulk power markets in a piecemeal fashion. The FERC Staff report states as much by noting:

> (1) Current transmission policies are not likely to be able to accomodate the options needed by the industry to make efficient investments in generation assets and probably not in transmission assets. One particular option, the emergence of a competitive generation sector, may be frustrated by the lack of a coherent and consistent

transmission pricing and access policy. (2) The current market power of transmission incumbents is so pervasive that independent power producers are unlikely to be willing to take substantial financial risks in the absence of assured access to the grid at reasonable prices. Without transmission reform, the potential efficiencies of a competitive generation sector will not be fairly tested.

Finally, for these who would say that relatively few self-dealing abuses under PUHCA mean the act is antiquated, NASUCA, suggests to the contrary, that what this means is that PUHCA's protections are valuable and are working. By this NASUCA does not wish to be labelled a "just say no" observer on the sidelines of the PUHCA debate. Instead, we are quite interested in actively participating in this crucial debate as this Committee demonstrates its responsible leadership.

FOOTNOTES

[1] *See, generally*, Council on Economic Regulation, *Competition and Regulation in Electricity Markets* (September 1988), at 6-7 and 37-38.

[2] 108 S.Ct. 2428 (1988).

[3] *See*, *eg*., R. Lark, "A Public Policy Perspective For Regulatory Reform in Response to Electric Competition," *Proceedings of the Twentieth Annual Williamsburg Conference*, Institute of Public Utilities, Michigan State University. (forthcoming in 1989), at 11 and "A State Consumer Advocate's Perspective on PUHCA Reform", *Proceedings of the Second Annual Conference on Electricity Law and Regulation*, American Bar Association (1989), at 11 (and oral remarks on March 13, 1989).

[4] *Remarks of Commissioner Charles A. Trabandt*, Edison Electric Institute Financial Conference, Palm Beach, Florida (October 18, 1989), at 6.

[5] *Inside FERC* (October 23, 1989), at 4a (emphasis in original).

[6] *Remarks of Commissioner Trabandt, supra*.

[7] P. Borre', *Give Us Access*, Edison Electric Institute Financial Conference, Palm Beach, Florida (October 18, 1989), at 7.

[8] Transmission Task Force of the Federal Energy Regulatory Commission, *Report on Electricity Transmission: Realities, Theory and Policy Alternatives*, (October 1989), at 187.

ATTACHMENT

7/18/89

NASUCA PUHCA REFORM SURVEY

Summary of Responses (Total of 11 Received)

1. Do you believe the structure of the utility industry in the future will be more competitive in nature?

Electric	9 yes	2 no
Gas	9 yes	2 no

2. Should it be?

Electric	8 yes	3 no	
Gas	6 yes	4 no	1 undecided

3. Regardless of whether or not it will or should be more competitive, do you believe State Utility Commissions will retain as much authority as possible in each of the following segments of the industry:

A. Generation

Electric	4 yes	4 no	3 undecided
Gas	4 yes	4 no	3 undecided

B. Distribution

Electric	7 yes	2 no	2 undecided
Gas	8 yes	1 no	2 undecided

C. Transmission

Electric	4 yes	4 no	3 undecided
Gas	3 yes	6 no	2 undecided

4. Should they retain as much authority?

A. Generation

Electric	9 yes	0 no	2 undecided
Gas	8 yes	1 no	2 undecided

B. Distribution

Electric	11 yes	0 no	0 undecided
Gas	11 yes	0 no	0 undecided

C. Transmission

Electric	9 yes	1 no	1 undecided
Gas	9 yes	1 no	1 undecided

5. Has your office ever participated at the SEC in any matter under PUHCA? (Specify if registered or exempt holding company.)

Electric	2 yes	9 no
Gas	2 yes	9 no

6. Has your office ever participated in any merger/acquisition or other type of case before your state utilities commission involving a holding company's formation or restructuring request?

Electric	7 yes	4 no
Gas	5 yes	6 no

7. In your opinion, should PUHCA be amended in order to allow non-utility power producers (true independents) to be created without PUHCA applying?

1 yes 6 no 4 undecided

8. Explain your response to Question 7.

CT) We would like to know more about the advantages and disadvantages of such actions. We are concerned with undercapitalized companies in general and with the fact that there may be more reliability in utility companies. We also note the following concerns: (1) advantages to consumers through least cost providers; (2) decrease in utility company nonregulated activities; and (3) diversion of management attention from regulated utility matters.

IA) Do not believe that if there are "true independents" they will remain "truly independent" if the market is lucrative.

KY) We need a fuller understanding of the benefits and detriments.

ME) Yes, if true independents are required to operate in a legitimate bid process. No, if there is any doubt about the "independence" of the bidders.

OH) Our Governing Board position is to oppose changes in the Act and we see no overwhelming reason to change the position now. Independent power is alive and well in Virginia, Maine, Texas, and California without changes in PUHCA. Why not let things develop as they are?

PA) I agree with EAF's view that competition from "true" independents will benefit customers.

SC) Either PUHCA as it exists should apply or some modification of PUHCA requirements. Unrestricted deregulation would be irresponsible.

TX) It will be difficult to define "true independent" power producer. The link between utilities and power producers will be strong for many years, until market conditions allow power producers full access.

UT) -----

WI) Captive customers need and deserve regulatory assurances in the area of supply, price, etc.

WV) Reliability is an important factor in electric generation. To the extent we rely more and more on IPPs instead of traditional bulk power supply for new generation to meet increasing demand, we must continue to ensure reliability. The tendency for unregulated IPPs will be to focus on profits rather than reliability.

9. Should PUHCA be amended for any other reason?

1 yes 3 no 7 undecided

SC) Some PUHCA amendments, coupled with FPA amendment or PURPA amendments should be explored to allow more flexibility for true independents but not affiliated power producers at this time.

10. Specify in as much detail as possible the potential abuses that could arise is true independent power producers (IPPs) are allowed to be created without PUHCA applying.

CT) Possible problems with (1) cross subsidy; (2) diversion of management attention or interests; and (3) capitalization problems.

IA) The potential abuses that could arise if the independent power producers are allowed to be created without PUHCA applying are as wide and as broad as the abuses that led to passage of PUHCA.

KY) -------------

ME) We are very concerned by the prospect of utility participation in IPP projects creating cross subsidies at the expense of captive customers and to the benefit of holding company shareholders.

OH) Financing and debt ratios, leveraged buyouts and hostile takeovers, cross subsidization, shifting of more costs to captive customers in order to cut prices to customers with alternatives.

PA) -----

SC) Greater potential for financial irresponsibility which could mean lower reliability if contractual agreements (nondisclosed) were broken.

TX) -----

UT) -----

WI) We haven't the experience in this specific issue to be of much help.

WV) Lack of reliability and cross-subsidization are the major problems. We've already seen cross-subsidization in the gas industry as a result of opening transmission and production to competition.

11. In your opinion, must the transmission access issue be linked to PUHCA reform?

Electric	5 yes	3 no	3 undecided
Gas	2 yes	5 no	4 undecided

12. Explain your response in Question 11 if yes or no.

CT) (E) N/A
(G) N/A

KY) (E) ------
(G) ------

IA) (E) If open transmission access is in the public interest, PUHCA should not be modified in any way.
(G) " " " " "

ME) (E) There can be no effective competition among generation (or conservation/load management) suppliers in the absence of access to the market. In New England, bottlenecks currently preclude such access for Northern New England QF's to Southern markets.
(G) " " " " " "

OH) (E) The issue of transmission access should be settled before any restructuring of the industry through NOPRs, PUHCA reform, or anything else.
(G) ". " " "

PA) (E) -----
(G) FERC is dealing with access anyway. PUHCA reform is basically irrelevant.

SC) (E) Plants could be built without assurance of transmission rights but since reliability is raised as a concern by utilities, it must be linked to PUHCA reform. Transmission access, however, may be handled separately.
(G) Open access already on its way toward attainment.

TX) (E) This industry will not provide access without a legislative mandate.
(G) This industry seems more willing to accept transmission access procedures. Less technical requirements are involved in gas transmission.

UT) (E) -----
(G) -----

WI) (E) Integral to supply to residential customers.
(G) " " " "

WV) (E) As with the gas industry, we could do this without PUHCA reform. A critical issue arises as to the responsibility of duty to expand capacity. This is not now a critical issue for the gas industry since demand has stabilized. There is no requirement in FERC Orders 436 or 500 to build new capacity if demand requires. However, this issue is an important reason to retain regulatory jurisdiction over at least some elements of electric transmission.
(G) We've already opened the transmission access function in the gas industry to competition without PUHCA reform.

13. Should it be linked?

Electric	6 yes	3 no	2 undecided
Gas	4 yes	4 no	3 undecided

14. Explain your response in Question 13 if yes or no.

CT) (E) N/A
(G) N/A

IA) (E) Same as (12)
(G) " " "

KY) (E) ------
(G) ------

ME) (E) The offsetting concern is that FERC initiatives governing transmission access will preclude any effective state act. Nonetheless Maine's successful experience with QF (and conservation) bid processes suggests that transmission questions must be resolved for optimal development of market potential.

(G) " " " " " " "

OH) (E) See response to (12).
(G) " " " " "

PA) (E) True competition is unlikely to occur without some reform in the transmission area.
(G) It's not necessary.

SC) (E) Greater reliability assured. Since utilities point to reliability as a concern (and it happens to be worth examination), transmission access and PUHCA reform are necessarily linked. But See #12 answer.
(G) With PUHCA amendment allowing more players in the market, the demand for gas lines will increase since gas is being used as fuel to generate electricity and will be in the future more often.

TX) (E) Same as (12)
(G) " " "

UT) (E) -----
(G) -----

WI) (E) Same as (12)
(G) " " "

WV) (E) As indicated above, if it is deemed wise to open transmission to competitive market pressures, it can be accomplished without relinquishing an important control over hiding companies, diversification and cross-subsidization.
(G) Already done without PUHCA reform.

16. Is your office on NASUCA-NET?

7 yes 4 no

THE ECONOMIC EFFECTS
OF S. 406

Prepared For The
Electric Reliability Coalition

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November 16, 1989

I. Introduction

S.406 was introduced ostensibly to remove a regulatory barrier to provision of an additional supply of electricity generation. The Competitive Wholesale Electric Generation Act of 1989 would amend the Public Utility Holding Company Act of 1935 (PUHCA) to create a class of Exempt Wholesale Generators (EWGs). These EWGs would be exempt from PUHCA, and the theory is that new EWGs would create new and needed capacity and would sell power to utilities.

Background

The occasion for concern in the electricity area is a result of many factors. Some observers are concerned that utilities may not be investing sufficiently to meet future capacity needs. Others are concerned that the industry may not be structured to provide least-cost electricity to consumers. Greater uncertainty, argue some, requires greater flexibility and an overhaul of the regulatory system in favor of more competition.

It is not at all clear that problems in the electric power area are of the magnitude necessary to warrant major, dramatic, and untested policy changes. For the better part of a century, the electric industry has provided cheap, reliable service and, although faced with severe and largely unforeseeable shocks in the 1970s, the industry has never failed to meet its obigation to serve. According to a recent study by the Office of Technology Assessment:

> The last 15 years have been difficult for many utilities, several having come close to bankruptcy,

> and have greatly raised costs for their customers. Since about 1983, however, most problems seemed to have waned. The cost of producing electricity has leveled out...[1]

The U.S. continues to enjoy some of the lowest electricity rates in the world. According to the Energy Information Agency, the average price in industrial countries for industrial electricity over the period 1980 to 1987 was 5.1¢/KWH. The price in the U.S. over the same period was 4.74¢/KWH. For residential electricity, the average industrial country price over the stated period was 8.12¢/KWH. The price in the U.S. over the same period was 7.01¢/KWH.[2] Nonetheless, dramatic policy changes are being seriously considered and the risks and rewards of such proposals must be assessed.

It is not the purpose of this document to philosophically debate general proposals for deregulation. The Johnston bill is a partial deregulation bill and this document will focus on resultant changes from the Johnston bill and whether they improve performance in key areas.

One is immediately struck by the magnitude of the crystal ball needed to judge deregulation proposals in general and the Johnston bill in particular. As was noted in the OTA study:

> **One notable feature of the debate over competition is the lack of data and analysis.** Experience with competition in the electric power industry has been limited, and much has not been

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[1] Office of Technology Assessment (OTA) Electric Power Wheeling and Dealing May, 1989, p. 4.

[2] Electrical World, July, 1989.

> relevant to a situation where competitively procured supplies represent more than a small part of the whole. **For the most part, the advantages and disadvantages discussed above are speculative.**[3] [emphasis in original]

Plausible Outcome

With little actual experience and an uncertain environment, the results of the Johnston bill are not readily apparent. Nonetheless, one plausible scenario results in successful entry by a new class of EWGs. This success is not based on underlying economic efficiencies, but by vestige of the fact that new entrants enjoy a highly favorable artificial cost of capital advantage through use of leverage and are competing with a utility capital structure that is constrained to a higher cost of capital. EWGs may enjoy a 20 to 30 percent cost of capital advantage which could lead to an apparent 5 to 10 percent electricity price advantage. This apparent price advantage, however, is obtained by imposing additional costs on utilities and/or society in general.

With little knowledge of the underlying efficiencies associated with the new EWGs, would this tax/finance induced successful entry and possible displacement of capacity be a good thing? Again the OTA study:

> We do not know how much more efficiently, if at all, non-utility generators can build and operate power plants. Nor do we know how much more difficult it will be to plan and operate a bulk power system that incorporates competition ... **Thus we cannot say whether economic gains induced**

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[3] OTA *supra* at 7.

> **by competition outweigh additional costs.**[4]
> [emphasis in original]

One of the items that separates the electricity business from other businesses is the absolute necessity of coordination among components. What will the existence of new entrants do here? The OTA comments:

> While some utility performance has been less than ideal, **separating a system's mutually dependent areas of decision making may introduce a different type of inefficiency that could be costlier than that intended to be addressed by competition.**[5] [emphasis in original]

It is often not understood that utilities supply more than one service. Deregulation proposals generally focus only on the development of capacity to produce kilowatt hours. Utilities, however, are actually multi-product entities providing a variety of essential services including: kilowatt hours, voltage regulation, frequency control, spinning reserves, system integrity, economic dispatch, transmission, coordination and emergency service, etc.

If competition occurs only for the supply of kilowatt hours, how will that affect the utilities' ability to supply frequency control services or the provision of reserves? Classic externality problems arise when the focus of deregulation is on only one service in a multi-product setting. Referring to the "dearth of information" the OTA states:

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[4] id.

[5] id.

> The uncertainty resulting from this lack of information could seriously hamper Federal and state regulators' efforts in: 1) assuring the fairness of the bulk power market, 2) assuring continued reliability of the system, 3) protecting the interests of the consumer, and 4) achieving other energy policy goals.[6]

Caution Should be Employed

Any proposal must be judged on its short and long run economic merits. Relevant criteria are economic efficiency, system reliability, energy policy goals, and consumer well-being. In a highly uncertain environment, the net benefit result of any proposal is, itself, highly uncertain.

This analysis will judge S.406 in light of the above criteria. The analysis relies heavily on the existing economic literature in several key subject areas. Section II will present one plausible scenario as to how S.406 might change the structure of the provision of wholesale power. In addition, this section discusses "risk shifting" and the resultant effects on utilities' financial situation, as well as the differential effects on the cost of capital for EWGs and utilities. Subsequent sections will comment on the implications of this structure for efficient, reliable, long run electricity provision. Section III discusses the important role of coordination in efficient and reliable power supply and Section IV relates the difficulty in achieving effective coordination when new entrants compete for generation in a post-S. 406 world. Section V delineates the types of

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6/ id. at 29.

contracts that would be necessary in a post-S. 406 world and compares them to the existing regulatory compact. Section VI outlines some energy policy issues raised by S. 406. Conclusions are offered in Section VII. The analysis concludes that, at best, the implications are uncertain and most likely are net-negative for long run economic health.

II. Potential Consequences of the Johnston Bill

Many uncertainties exist as to the potential consequences of an "incremental change", such as that proposed by S.406. Senator Johnston has claimed that, in and of itself, the bill requires nothing to happen, it merely solves an "antecedent" problem by removing a regulatory barrier to Independent Power Producer (IPP) development. However, a plausible scenario exists where the solving of the antecedent problem results in a class of new entrants that displace existing and incremental capacity, not by vestige of superior technological capability or resource efficiency, but instead because of a sizable artificial cost advantage bestowed on the new entrants at the expense of existing utilities, due to the interworkings of financial structure and the tax code, and a possibly temporary low level of natural gas prices. This section describes this scenario and presents one possible view of a post-S.406 electricity industry landscape. It is left to later sections to judge whether the changed landscape is beneficial or not.

Proponents of the Johnston legislation have argued that substantial new electrical generating capacity will be needed in the future and that utilities, constrained by the current regulatory environment, are not meeting that need. Increased competition, it is argued, will allow a new class of entrants to provide the investment necessary to meet future capital requirements. But by definition, new entrants will not compete solely for incremental business. Where opportunities exist, new entrants will also compete for existing business.

As opposed to PURPA, there is nothing in the Johnston bill that would require a utility to purchase power from an EWG. If, however, the EWG was able to supply power more cheaply over some time frame, for any reason, utilities would either voluntarily, or under compulsion from state PUCs, purchase power from EWGs. It would be naive to assume that successful entry, or even factors that lead to substantial pressure for EWGs to enter the bulk power market, would not force the issue of transmission access for wheeling purposes to the forefront. As was stated in a recent FERC Transmission Task Force study on the nation's transmission system:

> The pressure for transmission access in the future is likely to come not only from retail and wholesale customers, but also from independent suppliers... Independent power producers, QFs, and state-sponsored bidding procedures will create a need for transmission access policies that ensure owners of generating plants that transmission service will be available when needed.[7/]

In all likelihood, passage of S. 406 would lead to serious

[7/] Transmission Task Force The Transmission Task Force's Report to the Commission, FERC, October 1989, p. 67.

consideration of transmission access. Even without mandatory access for wheeling, displacement of generation capacity by EWGs would occur through sales to host utilities. According to one proponent of IPP development, Paul J. Elston, "it is clear, from the bidding experience to date, that lack of transmission access has not stifled competition and therefore is not essential to the development of a competitive generation market."[8] If this displacement of incremental or existing uility-owned generation was the result of greater efficiencies on the part of the EWGs, and was consistent with long-run reliability concerns, then the Johnston legislation would have accomplished its goal--removing a regulatory impediment to more efficient provision of electric power. If, however, the displacement occurs due to artificial tax induced cost of capital advantages, (as well as the fact that EWGs can avoid costly reliability services), then the legislation may produce anamolous results contrary to the intent of the legislation's sponsor.

Take-or-pay Contracts

There is one area of this possible new landscape that must be described prior to a discussion of legitimate and illegitimate competitive criteria -- the contractual arrangements that would have to exist in a post-S.406 world between utilities and EWGs. The economics of such contracts are discussed in detail in

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[8] Paul J. Elston "Will IPPs Dominate the Market? -- Impact of NOPRs and PUHCA", delivered to the Fourth Annual Cogeneration and Power Market Conference, p. 10.

Section V. Many writers have commented on the types of contracts that would be needed if competition in generation were to occur. One author has stated:

> I do know that the members of the financial community with whom I have spoken, and this includes people who claim to be able to raise capital for independently owned generating stations, uniformly say that financing of these stations would be possible only with full payout (i.e., life of facility), take or-pay contracts from utilities.[9]

Another description of the contractual arrangement holds that contracts would be long-term (10 or 20 years), take-or-pay, with complicated formulas so that the purchaser (utility) will bear the risk of fuel cost increases (via a cost pass-through arrangement).[10] These types of arrangements will have a serious impact on the effectiveness of competition in a post-S. 406 world.[11]

Legitimate Competitive Criteria

What might the relative cost advantages be in a post-S.406 world and who might take advantage of these advantages? The legacy of the 1970s was one of escalating fuel and capital costs. The latter increase, in combination with regulatory tension, has made both existing utilities and potential entrants wary of large capital intensive investments. Both of these groups might be led to follow a strategy of capital minimization:

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[9] Irwin M. Stelzer "The Electricity Debate: They Do Not Know That They Believe: They Believe That They Know" NERA, September 21, 1981.

[10] Paul L. Joskow and Richard Schmalensee, Markets for Power (MIT Press -- Cambridge 1983) p. 135.

[11] Some PURPA QFs do have contracts other than the absolute take-or-pay variety. These are small in nature and are guaranteed sales at the utility's avoided cost, but without any minimum take-or-pay obligation. Larger projects, without the PURPA protection, will need the type of take-or-pay contracts described here.

> Some observers are concerned that under the present regulatory environment utilities will jeopardize future reliability and cost control by failing to construct needed facilities or building only plants with the lowest possible capital cost, such as oil-or gas-fired turbines, which often have high operating costs. Others are concerned that capital minimization is exactly the choice that most competitive generators would select.[12/]

It stands to reason that many of the new entrants would employ capital minimizing strategies resulting in investment in power supply short-term alternatives such as gas-fired turbine facilities. Separately owned firms that do not serve a franchise area and do not have a commitment to native customers to ensure sales would not be concerned about the long-term impact of decisions on utility customers or shareholders. To a large extent, their objective would be to mitigate their own risk by using resource-intensive, low capital technologies. If new entrants were to exist in a post-S.406 world, they would be of this variety.

Consider the case of gas-fired turbine based companies competing in an existing market with utilities. What types of competitive advantages might the new entrant enjoy (ignoring, for now, long run social goals)? There is nothing inherently

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[12/] OTA supra at 5.

superior about the gas-fired technology employed by EWGs. In general, such turbines are used in combined-cycle configuration for base-load capacity, or as individual units for peaking capacity. Whether electricity can be supplied more cheaply at any point in time by gas-fired units relative to other types of generation is a function of the trade-off between capital and fuel costs. According to the OTA:

> Nuclear and coal plants have low fuel costs compared to gas-and oil-fired plants. If their capital costs are not too high, the fuel cost advantage can result in lower overall cost per kilowatt hour. At the moment, this is probably not the case. Oil and gas prices are not much higher than coal though gas prices are climbing. Future competitiveness for nuclear and coal will depend on holding capital costs down as well as renewed increases in oil and gas prices. Despite the spectacular cost increase in the seventies, this appears possible. Some of the factors driving these increases were peculiar to the times (20 percent interest rates and construction delays due to plummeting demand). Others are one-time increases that would not continue pushing prices up ...13/

There may be a transitory competitive advantage afforded new gas-fired projects due to the current level of gas prices. Such advantages are legitimate in any competitive process. As long as the playing field is level, the physical capital - fuel cost trade off should be one determinant of competitive outcome. In addition, entrants using gas-fired technologies are capable of achieving unit economies of scale at 100 MW or less.14/

13/ id. at 5 note 3.

14/ FERC Power Pooling in the United States, December 1981, p. 16.

Illegitimate Cost Criteria

If competition for existing and incremental load after the Johnston bill were based on only such issues as resource efficiency and scale, then the competition would be a "fair fight" and the economic outcomes would be arguably proper. Senator Johnston has stated:

> In general, advocates of change point out that the Holding Company Act legislation merely creates the option but not the requirement for independent power production, one must assume serious and prolonged errors in judgment by both purchasing utilities and state regulatory commissions in order to argue that the nation's electrical supply would be harmed by the legislation. In other words, if in a given instance IPP power is unacceptable, it simply need not be purchased.[15]

Recent history in an area outside of energy economics has pointed out that perfectly rational economic agents can be induced to make decisions that may be in their own private interests but antithetical to economic efficiency and social wellbeing. The Tax Reform Act of 1986 was landmark legislation enacted in large part because differential tax treatment was perceived as causing extreme biases in flows of investment. Tax favored investments were made to the extent that the nation's capital stock was viewed as skewed and inefficient. The tax code was believed to be producing differences in the financial costs of capital among industries resulting in over-investment in some industries and under-investment in others. These tax-induced cost of capital distortions were thought to cause losses to the economy in the billions of dollars.[16] Although some observers would argue that the objective was not met, a primary goal of the 1986 Act was to reduce tax-induced cost of capital distortions so that investments were based on economic merits, not on artificial financial biases.

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[15] Statement by Senator Bennett Johnston (D. La.) concerning S.406, p. 2, 3.

The Johnston bill would create a situation where competition for existing and incremental power load would be based almost solely on the types of cost of capital distortions that the 1986 Act sought to remove. In areas where additional capacity was needed, or even with respect to existing business, new independent EWGs would successfully compete, not on the basis of superior technology, coordinating or management skills, but because they enjoyed a dramatically but artificially lower cost of capital. In addition, EWGs only have an interest in producing KWHs and would attempt to avoid costs associated with voltage and frequency control as well as other services, thus affording a further artificial advantage. Thus, utilities would play by one set of rules, while new entrants would play by an entirely different set.

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[16] See, Jane G. Gravelle "The Social Cost of Nonneutral Taxation: Estimates for Nonresidential Capital" in Depreciation Inflation & The Taxation of Income from Capital, Charles R. Hulten, ed. (Urban Institute -- Washington, D.C., 1981), pp. 234-250; and Patric H. Hendershott and Shen-Cheng Hu "Government-Induced Biases in the Allocation of the Stock of Fixed Capital in the United States" in Capital, Efficiency and Growth, George M. Von Furstenberg, ed. (Ballinger -- Cambridge, 1980), pp. 323-360.

Existing utilities employ a large amount of equity in their capitalization structures. In some cases, this is because of PUHCA requirements and SEC oversight. In others, it is a result of financing realities. The capital-intensive electric utility needs to maintain a high equity ratio in order to secure a favorable credit rating, so that it can efficiently raise the capital required to sustain the business. This is especially true because the overwhelming majority of financial risk is imposed on the utility. In 1987, 50.6 percent of utility capital was debt financed and 49.4 percent was equity.[17]

This is in stark contrast to the probable financial structure of the new entrant EWGs. Past experience with PURPA and the opinions of most observers lead to the conclusion that most EWGs will be highly leveraged with debt levels at or above 90 percent. According to Glenn P. McIsaac of Energy Management Associates, Inc., there is a "presumption that independent power projects will continue to be financed with up to 90% debt capital, while utility debt ratios generally range from 45% to 50%."[18]

S. 406 Would Result in a Non-level Playing Field

S. 406 would allow existing utilities to set up EWGs and, therefore, supporters of the legislation claim that the same cost of capital advantages are available to utilities for incremental investment as for independent EWGs. In fact, this is an illusion.

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[17] OTA *supra* at 52.

[18] Glenn P. McIsaac "IPP Financing Advantages: Separating Fact from Fiction", p. 12-2.

One must ponder whether any truly competitive market could sustain 90 percent debt levels for the various corporate entities. In no other competitive industry are such debt levels apparent. In manufacturing industries, for instance, capitalization ratios tend towards about 65 percent debt, and these industries are less risky than electric power.

There is an enormous amount of risk associated with long-gestation, capital-intensive investments where plant and equipment are highly specialized and completely immobile and fuel costs and load are uncertain over the life of the facility. It is not PUHCA that results in the levels of equity that exist in the electric power industry, nor are registered holding companies the only ones to have 50 percent equity in their capital structures. Because of the risk inherent in electric power, it is the market which requires such high levels of equity. If a corporate entity in the electric power industry is able to sustain very high leverage, it can only be because the enormous risk is shifted off of that entity and on to someone else. Otherwise the risk premium in interest rates would far exceed the tax advantage to debt and, absent any major economic efficiencies, the leveraged entity could not compete.

To the extent that EWGs are successful, it will only be because the contractual arrangements will result in all the risk being borne by the utility. It is irrelevant if the debt is non-recourse. The types of contracts likely to emerge in a post-S. 406 world have already been described. According to McIsaac "[t]hese commitments typically provide the independent producers with an assured market and a known price for their facilities' output. These assurances are important because they assign the 'market risk' to the utility rather than the IPP."19/ Glenn Ikemoto and Susan Carlow, two insurance industry executives, have noted the same effect:

> The long-term contract with price certainty and guaranteed sales removes the market risk from the venture. With an assured revenue stream, even the smallest developers can finance huge projects on a non-recourse basis.20/

Robert W. Burke of Moody's Investors Services states that an "absolute 'take or pay' contract places the risk of both demand and operating performance on the purchasing party."21/

In fact, EWG debt will be almost certainly attributed to the purchasing utility, regardless of whether the utility owns the EWG. This is obvious in the statements of rating services executives. Thomas D. Mockler, Senior Vice President for Standard & Poor's Corporation, has stated:

19/ id. at 12-3.

20/ Glenn Ikemoto and Susan Carlow "Power Contract Security: Balancing Price and Quality", p. 11-2.

21/ Robert W. Burke "Independent Power Producers and Their Impact on Utility Debt Quality" before the Energy Daily's Annual Utility Conference, Washington, D.C., November 2, 1989, p. 6.

> Where an obligation exists for the utility to make minimum capacity payments to its energy supplier under (effectively) all circumstances, we regard the present value of the annual payment obligations as debt of the utility... The purchase power payment obligation is equivalent to the debt service obligation a utility would incur if it financed its own plant with 100% debt leverage.[22]

Moody's Investors Services concurs with Standard & Poor's:

> Regarding the impact of long-term take-or-pay contracts for purchasing electric power on the credit quality of a purchasing electric utility, Moody's believes credit risk may well be increased by these contracts. Contract obligations should be viewed as effectively increasing the purchasing electric utility's debt leverage and debt service requirements.[23]

This attribution of EWG debt to the purchasing utility creates a situation where EWG leverage, and the corresponding cost of capital advantage, can only occur because of an offsetting cost of capital disadvantage to the purchasing utility. According to McIsaac, for the "purchasing utilities, such commitments increase financial risk exposure and result in a higher cost of capital, and higher required equity ratios."[24] Ikemoto and Carlow argue that, "[a] business taking both production and market risks would need significantly more equity."[25]

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[22] Thomas A. Mockler, letter in response to a request by Senator McClure, February 9, 1988, p. 3.

[23] Comments of Moody's Investors Service before the United States Senate Committee on Energy and Natural Resources, February 12, 1988, p. 2.

[24] McIsaac *supra* at 12-2.

[25] Ikemoto and Carlow *supra* at 11-3.

The cost of capital increase to the utility is due to an erosion in the utility's credit rating when there is a greater reliance on independent power and/or the increased need for equity in the capital structure of the utility. According to Moody's Investment Services "[g]reater reliance on purchased power, especially if costs and reliability are placed outside the utility's control, is likely to erode quality and lead to lower Moody's ratings."[26] Thus, "situations are likely to arise which will increase a utility's cost of capital."[27] The reasons for the increased cost of capital to the utility are twofold:

> If credit quality is deteriorating, the utility's overall cost of debt and equity capital will increase because of (a) the higher cost of debt that would be issued in the future, and (b) the higher risk to the equity holders because of increasing business risk.[28]

The cost of capital advantage to an EWG is offset by a cost of capital detriment to the purchasing utility. Two different scenarios need to be examined. In the first, an independent EWG, which is a separate corporate entity, contracts to sell power to a utility. In the second, a utility sets up its own EWG, and buys power from it.

In the first scenario, the independent EWG, as a separate corporate entity, enjoys a real cost of capital advantage. The associated risk costs are external to the EWG and are imposed on another corporate entity, the utility. As such, the independent EWG can make use of its cost of capital advantage and price power at a lower price.

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[26] Burke supra at 6,7.

[27] id.

[28] Moody's Comments supra at 2.

In the second scenario, the utility's EWG can only produce a cost of capital advantage by imposing additional costs on the parent corporation, since the EWG and the utility are contained in one corporate entity. The associated risk costs are internal to the corporation, which has no external place to shift the risk. As such, there is no net cost of capital advantage to the corporation and it cannot price electricity at a lower price.

Thus, S. 406 would result in a dichotomy in costs of capital between two different types of corporate entities. Independent EWGs would have an artificially lower cost of capital, and traditional utilities and EWG/utility combinations would be constrained to the cost of capital facing traditional utilities. The magnitude of this cost of capital differential is discussed in the next section.

The Cost of Capital for EWGs versus Existing Utilities

This section reports the results of a comparison of the calculation of the cost of capital facing an existing utility making an investment alone or as part of a utility-owned EWG (with proper cost of capital offset) and the cost of capital for a new EWG.29/ The generally accepted definition of the

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29/ As was illustrated in a previous section, an EWG/utility combination that is part of one corporate entity is effectively constrained to the same capital structure as a traditional utility.

"financial cost of capital" is the pre-tax return needed to generate the required "hurdle" after-tax rate of return to the investor. In other words, individual investors require a specified inflation adjusted after-tax rate of return to justify investment in a project. The financial cost of capital is the pre-tax return needed to produce that hurdle rate, given inflation; state, local, and federal income and property taxes; economic decay and obsolescence rates; depreciation treatment; capital structure; risk; etc.[30]

The methodology employed here follows exactly the model developed and used by the U.S. Treasury Department during deliberations on the 1986 Tax Reform Act. The model was designed primarily by former Assistant Secretary of the Treasury Don Fullerton.[31] Although other variations on this theme exist, the Fullerton methodology is the most generally accepted and widely used.

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[30] As was discussed in the previous section, under expected contractual arrangements, all EWG risk is transferred to the purchasing utility. Thus, investors in an EWG will require no more risk premium than for a traditional utility investment, despite the highly leveraged, non-recourse nature of EWG financing.

[31] For a description of the methodology, see Don Fullerton "The Indexation of Interest, Depreciation, and Capital Gains and Tax Reform in the United States," Journal of Public Economics, February, 1987, pp. 25-51; Don Fullerton and Yolanda K. Henderson, "A Disaggregate Equilibrium Model of the Tax Distortions Among Assets, Sectors, and Industries," International Economic Review, May 1989; and Don Fullerton and James B. Mackie, "Economic Efficiency in Recent Tax Reform History: Policy Reversals or Consistant Improvements?," National Tax Journal, March, 1989, pp. 1-13.

The analysis begins by calculating the discount rate firms employ to assess future cash flows of all sorts. Since this rate is a function of capital structure, inflation, individual tax rates on debt and equity, and corporate level tax treatment of debt versus equity, the calculation explicitly incorporates investor tax structure and the debt/equity ratio. The net average rate of return to the individual investor is set by assumption after reviewing the existing evidence. In this case the required real after-tax return to the individual investor is assumed to be 6 percent. This is consistent with equity returns at the corporate utility level of 14 to 17 percent.[32/] In addition, experiments were performed setting the hurdle rate at 4 percent and 5 percent. These experiments tested the sensitivity of the EWG/utility cost of capital differential to the hurdle rate assumption.

Once calculated, the discount rate discounts all cash flows, including depreciation deductions. Employing the assumption that a corporation would only invest one dollar if the present value of the real-after-tax income stream were one dollar, the financial cost of capital can be mathematically determined.

Required data include information on obsolescence or capacity decay; all individual and corporate state, local, and federal tax provisions affecting investment; an assumed inflation

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[32/] The corporate level equity return is dependent upon the proportion of the capital stock originally financed by retained earnings versus new shares paying dividends.

rate; assumptions as to risk premiums;[33] information on the income-generating properties of the investment; capital structure; and an assumed hurdle rate of return for the individual investor.

The financial cost of capital is the overall cost, per dollar of investment, needed to produce the requisite return to the individual investor. Thus, it is essentially a weighted average, the weights being the proportions of debt, new shares, and retained earnings.

Data

Information on individual state and federal income taxes is based on the National Bureau of Economic Research TAXISM model as reported in papers by Fullerton.[34] The corporate tax rate (including state and federal taxes) comes from two sources.[35] The property tax rate on utilities also comes from Fullerton.[36] The inflation rate is assumed to be 4 percent per year.

The economic value of investment (which declines because of obsolescence and capacity decay) is assumed to decline at a geometric rate as per the literature. Stand-alone gas-fired turbines are assumed to have decay rates of 7.86 percent per year based on research by Hulten and Wykoff.[37/] The geometric rate for combined-cycle and coal-fired steam generators comes from an extrapolation based on Hulten and Wykoff and information provided by the Congressional Research Service.[38/] The assumed annual decay rate is 5.6 percent per year.

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[33] As was previously stated, no additional risk premium is needed by an individual investor investing in an EWG. This is because the purchasing utility bears, implicity or explicity, all risk associated with an EWG/utility power contract.

[34] Fullerton *supra* at 31, 32.

[35] Merlyn A. King and Don Fullerton, The Taxation of Income from Capital (University of Chicago Press -- Chicago 1984), p. 204 and Fullerton *supra* at 31.

[36] Fullerton *supra* at 31.

As was previously stated, it is assumed that the average net real return to the individual investor (the hurdle rate) is 6 percent, which is consistent with the range of observed utility equity yields.[39/] Additional tests set the rate at 4 and 5 percent.

The tax depreciation treatment is crucial to the cost of capital calculation. Under the 1986 Act, assets are assigned to a depreciation class based on their Asset Depreciation Range (ADR) class lives. Stand-alone gas-fired turbines are assigned

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[37/] Charles R. Hulten and Frank C. Wykoff "The Measurement of Economic Depreciation" in Depreciation, Inflation, and the Taxation of Income from Capital, Charles R. Hulten - ed. (Urban Institute -- Washington, D.C. 1981), p. 95.

[38/] Id. and Jane Gravelle, unpublished capital stock proportions and capacity decay rates. Congressional Research Service 1984.

[39/] If a hypothetical utility is financed 100 percent by new shares and the investor hurdle rate of return is 6 percent, then the cost of capital is 16.6 percent, based on the model simulation. If the utility is financed 50 percent by new shares and 50 percent by retained earnings, the cost of capital is 14.9 percent. Here, the cost of capital is equivalent to the corporate level return to equity.

to ADR class 49.15 which has a 20-year class life.[40] The actual tax depreciation life is, therefore, 15 years.[41]

If a gas turbine is used as part of a combined-cycle facility, however, the entire facility is contained in ADR 49.13. This class has a 28-year life, resulting in an actual tax depreciation life of 20 years.[42] Coal-fired steam generators are also contained in this class.

For stand-alone turbines, combined-cycle facilities, and coal-fired steam generators, the 150 percent declining balance method of depreciation is used.[43]

Results

Given the above data and the mathematical model, the cost of capital can be calculated for utilities' existing facilities and compared to the cost of capital that would face a new EWG. Since the cost of capital is based on an assumed hurdle rate of return to the individual investor, the calculations are more appropriate for judging the relative levels of the cost of capital between utilities and EWGs than for judging the absolute values.

It is assumed that an existing utility's capital was placed in service after the 1986 Tax Act was in effect.[44] The utility's

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[40] 1989 Depreciation Guide, Commerce Clearing House 1989, p. 104.

[41] Internal Revenue Code, Sec. 168(e)(1), Sec. 168(c)(1).

[42] 1989 Depreciation Guide supra and Internal Revenue Code supra.

[43] Internal Revenue Code, Sec. 168(b)(2)(A).

Continued

existing facilities are assumed to be financed with a 50 percent debt/equity ratio.[45] Three possibilities are considered for the equity portion: (1) the entire equity portion is funded by new shares, (2) the entire equity portion is funded by retained earnings, and (3) half is funded by retentions and half by new shares.[46]

The EWG is considered under three funding schemes: (1) 90 percent debt and 10 percent new shares, (2) 95 percent debt and 5 percent new shares, and (3) 100 percent debt.

Cost of capital can be compared as can a related concept, the marginal effective tax rate. The marginal effective tax rate is defined as the percentage difference between pre- and post-tax rates of return. It is the true tax rate on the last unit of investment. Here, the effective tax rate is the percentage difference between the cost of capital (the pre-tax return) and the assumed hurdle rate (the post-tax rate of return). The effective tax rate is a generally accepted method of measuring the "tax wedge" in investment costs.[47]

44/ This is for computational ease. The calculation becomes more difficult for facilities straddling two tax regimes. Of course, all prospective investment is covered by the 1986 Tax Reform Act.

45/ Based on OTA *supra* at 52.

46/ As reported in OTA *supra* at 51, a Salomon Brothers, Inc. study predicted that 77 percent of new utility investment would be funded by retentions in 1988, 85 percent in 1989, and 90 percent in 1990. This is compared to 33 percent in 1980.

47/ The effective tax rate was used frequently during the debate on the 1986 Tax Act. *See*, for instance, the 1987

Continued

Table 1 shows the results of cost of capital calculations for existing utility capital and new EWGs and the corresponding effective tax rates. Depending on the type of technology employed and the capital structure, the EWG enjoys an 18 to 39 percent cost of capital advantage over existing utilities. Most likely the cost of capital advantage to EWGs will be in the 20-to-30 percent range. For the experiments employing a 4 and 5 percent hurdle rate of return to the investor, the cost of capital differential was even larger than when the rate was set at 6 percent. The existing marginal effective tax rates are much higher for existing utilities than for EWGs. Figure 1 compares the effective tax rate for a typical utility (capital financing: 50 percent debt, 25 percent retentions, 25 percent new shares) with a typical EWG employing a combined-cycle facility (95 percent debt, 5 percent new shares). For this situation, the utility's effective tax rate on capital is almost 50 percent higher than the EWG's.

Economic Report of the President.

Table 1

Cost of Capital for Existing Utilities
versus
New EWGs

Funding[48]	Cost of Capital	Effective Tax Rate
UTILITY		
50% Debt 50% NS	11.36%	47.2%
50% Debt 25% NS 25% R	10.87%	44.81%
50% Debt 50% R	10.41%	42.36%
EWG -- Stand-alone Gas-fired Turbine		
90% Debt 10% NS	8.7%	31.04%
95% Debt 5% NS	8.45%	28.96%
100% Debt	8.2%	26.86%
EWG -- Combined-cycle Plant		
90% Debt 10% NS	8.85%	32.17%
95% Debt 5% NS	8.59%	30.18%
100% Debt	8.35%	28.16%

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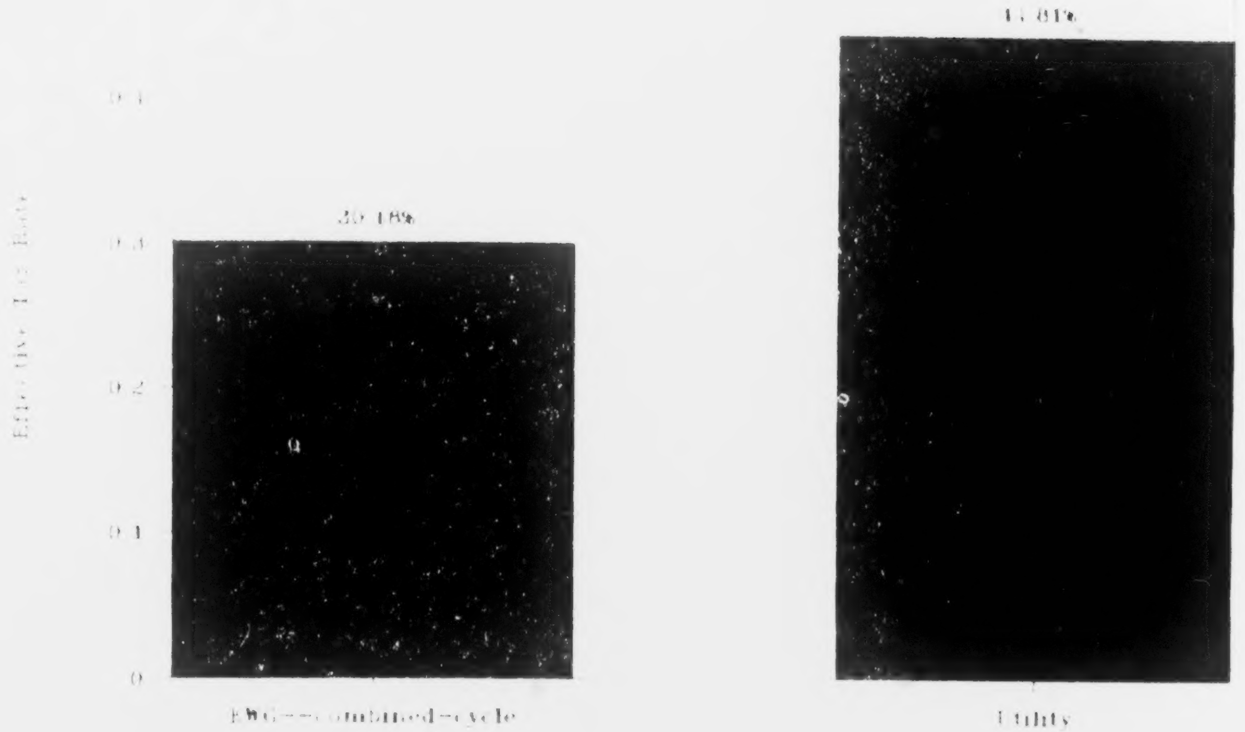
[48] NS stands for new shares paying dividends.
R stands for retentions.

FIGURE 1--Marginal Effective Tax Rates

New EWG versus Existing Utility



Cost of Capital and KWH Prices

This analysis has shown that a new EWG enjoys a 20-to 30-percent cost of capital advantage over an existing utility employing a traditional capital structure. It has been estimated that capital costs account for about 20 to 40 percent of the price of a KWH of electricity. Thus, on average, the artificial cost of capital advantage would allow an EWG to price electricity 5 to 10 percent lower than an existing utility or EWG/utility combination, all else held constant. Of course, the EWG enjoys this private price advantage only by imposing social costs, either on the utility's shareholders or eventually on ratepayers. These social costs represent externalties which may not, but should be considered in any bidding process or prudency review. As stated by Glenn McIsaac:

> [T]he apparent lower cost of IPP power, may not reflect a true cost savings to utilities and rate payers...
> An "equivalent leverage" approach should be used to evaluate the financial consequences of purchases from IPPs. Increases in the utility's cost of financial capital which are expected to result from commitments to IPP generation should be included in cost comparisons of IPP and utility-owned generation.49/

If a true accounting of the implicit financial costs associated with EWG production were obtained, most EWG projects would not be competitive. The danger is that local PUCs, operating under their existing incentive systems, will not properly account for all costs. This is especially true because

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49/ McIsaac supra at 12-1, 12-2.

these costs are extremely complex and difficult to explain theoretically, more less quantify. In fact, there is some evidence that such costs are not being accounted for in existing competitive situations:

> Energy Management Associates, Inc. has reviewed most of the competitive bidding systems adopted by utilities across the country. None of the evaluation procedures in the bidding systems reviewed explicitly recognize the financial risks associated with commitments to purchase power from IPPs. Instead, the prices bid by independent suppliers are compared directly to the costs of traditionally financed utility construction.50/

Thus, there is a clear danger that the apparent price advantage of EWG power will be considered to be real. The result would be reliance on power sources with no real cost advantage and displacement of traditional utility generation.

Conclusion

It is always difficult to predict the outcome of legislative changes that break new ground, especially if the changes are of an "incremental" nature. Senator Johnston has stated that his bill requires nothing and merely sets up a new supply option, which will only be utilized on the basis of economic merits. In fact, the bill doesn't merely remove a regulatory impediment to a new supply option. It sets up a new class of entrants so that there are two distinct sets of "competitors" for incremental and existing business playing by two sets of rules that have nothing to do with underlying energy economics. One class, existing

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50/ id. at 12-4.

utilities, are constrained to a capital structure employing large amounts of equity which is disadvantaged under our tax regime. The other, EWGs, are free to enjoy a highly leverged, dramatically lower cost of capital.

This artificially lower cost of capital may be sufficient that utilities are compelled (either voluntarily or though PUC pressure) to enter into long-term take-or-pay contracts with EWGs containing cost passthrough provisions. In addition, this artificial advantage may force the transmission access issue to the forefront. As was discussed, the long-term take-or-pay contract with the utility not only enables the EWG to enjoy this competitive advantage, but it also uses up a portion of the utility's credit and could drive the utility to even higher equity ratios in the future. In essence, the utility will bear much of the financial risk. The magnitude of the potential success of EWGs is unknown but one plausible scenario results in a new landscape where EWGs employing gas-fired turbines provide a non-trivial portion of generation.

The next sections will discuss the long run implications of such a change.

III. What Will New Entrants Do To Coordination for Economy and Reliability?

The electric power industry is unique in many ways. The entire functioning and structure of the industry is slave to the laws of physics in a way that no other industry is. The entire production/transmission/distribution system must obey the laws of physics at every instant. Every component of the system is, at every moment, dependent on every other component. The failure of even a small, isolated component can require redistribution of generation or some other operating procedure to be implemented to prevent damage to facilities or system wide failure. As such, the entire system is hostage to even small independent elements. The result of poor coordination can be disastrous:

> Generating plants connected to the same power system cannot operate independently of one another. This is a physical impossibility. Unless generation in the aggregate matches load, on a second-to-second basis, large scale outages may occur, and damage to generation and transmission assets is likely.[51]

No other industry is physically constrained in this manner and relies so heavily on coordination. It is generally accepted by most observers that the electricity industry depends on wide scale cooperation both for provision of least-cost power, and for continuous reliability. Any proposal which brings in new competitors to one part of the industry must be judged on its effects on coordination. This is especially true if the new entrants achieve competitive advantage, not on the basis of underlying economic efficiencies, but on the basis of artificial financial advantages.

Least-Cost Power

Most commentators believe that coordination is important to achieving least-cost power:

51/ Joskow and Schmalensee, supra at 113.

> [T]here appear to be substantial system economies that can be only fully exploited by coordinating generator dispatch, generator expansion and transmission over large areas. While there are sharp disagreements over the extent of these coordination economies, they probably extend at least to the regional level.52/

To achieve least-cost power, the system must optimize in three different directions. It must have a long term view that allows costs to be minimized over the long-term, at least 20 years. This is relatively easy under vertical integration because all the components are internalized and have the same time horizon. It is much more difficult if different components, acting solely in self-interest, have different time horizons. The second dimension to system optimization is to optimize over all the components in the system. The third dimension is to optimize over the relevant geography.53/

Least-cost power requires many attributes: interconnection in a regional transmission and coordination system, economic centralized dispatch, maintenance coordination, coordination to pool the risks of emergencies, and coordination for investment planning and guarantee of sufficient capacity. One of the thorniest areas in post S.406 world may be economic dispatch but this would be essential according to the OTA:

52/ Stelzer, supra at 11.

53/ John A. Casazza "Free market Electricity: Potential Impact on Pooling and Coordination" Public Utilities Fortnightly, February 18, 1988.

> To minimize operating costs under competition, centralized control of dispatch or other mechanisms to select lowest cost of generation must be established.[54]

Economic dispatch is essential to least-cost energy over both the short and long run. The system must be flexible enough to employ the optimal mix of fuel over time. At any point in time, the system must choose the least cost mix of technologies and existing facilities for base-load, cycling, and peaking. Such planning must occur at a high level of aggregation to achieve all economies.[55]

It is generally agreed that all system economies have not been exhausted. Thus, consumers could achieve lower prices if more coordination existed, not less. Some commentators believe that there are many firms that are too small and that horizontal integration would lead to lower costs.[56] They argue, for instance, that inefficiencies result from "the presence of independent firms too small to realize internally all economies of scale."[57] A Department of Energy study concluded that full integration was necessary to achieve the lowest costs.[58]

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[54] OTA, *supra* at 18.

[55] Joskow and Schmalensee, *supra* at 18.

[56] *id*. at 58.

[57] *id.* at 85.

[58] U.S. Department of Energy, *Power Pooling: Issues and Approaches*, Washington, DC, January 1980.

In order to minimize costs many utilities participate in some form of pooling arrangement. One study estimated that such coordination agreements save U.S. consumers over $15 billion per year.[59] This same study argued that, if not for pooling, 14 percent additional generating capacity would be required currently and 20 percent more would be required in the 1990s.[60] It has been estimated that central dispatch in the Florida Brokerage Agreement region would save an additional $20 million.[61] It has been estimated that potential coordination in the Virginia-Carolinas area (VACAR), if implemented, would result in an average 7.7 percent total cost savings. Simulations for the Central Area Power Coordination System estimated coordination savings of $850.4 million between 1976 and 1985. The Illinois-Missouri Power Pool simulations suggested savings of $115.4 million over the same period. The number over this period was $224.7 million for the Kentucky-Indiana Pool.[62]

If least-cost power is a goal of policymakers, then any proposal must be judged on the basis of its effects on coordination. Equally important coordination benefits pertain to areas of safety and reliability.

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[59] Casazza, supra at 17.

[60] id.

[61] FERC, supra.

[62] id. at 185-191.

Multiple Products, Externalities and Reliability

Coordination is essential for the reliability and safety of an electrical power system. Because most electric power is supplied by vertically integrated firms it is easy to lose sight of the fact that utilities do much more than simply sell kilowatt hours to customers. The system is dependent on the utilities' supply of a host of intermediate products and services such as voltage regulation, frequency control, spinning reserves, non-spinning reserves, etc. The private market would not necessarily compensate generators separately for these other services but these services are essential to the integrity of the system.

No other industry is as interdependent as electric power. If a power plant fails suddenly, its loss must be made up instantly. Cascading outages can occur, jeopardizing electric service to wide areas. Comprehensive system engineering studies including thorough analysis of the stability conditions of each system must be conducted frequently. If frequency is reduced, there must be an instantaneous response. Only system wide coordination of the planning and operations of utility systems can result in a reliable system. The entire system and all its components must operate with coordinated voltages, frequencies, coordinated emergency reserves, and coordinated stability analysis. Transmission must also be coordinated across all the generating components because "the overall system's transfer capacity is constrained by the single most limiting line."[63/]

Under a vertically integrated system, or a pooling system involving a small number of vertically integrated utilities, reliability is fairly straight-forward, especially since all entities are bound by a legal obligation to serve. But what happens when new entrants operating solely in their own self-interest, enter the market?

The new EWG is concerned only with the sale of kilowatt hours. The provision of the other products (voltage regulation, etc.) have no direct market. The utility is compensated for such services under the regulatory compact. Since a competitive market does not ordinarily compensate separately for such reliability services, a tension exists and the possibility for a classic externality problem exists.

This externality possibility is magnified a thousand fold in the case of an industry as intertwined as electric power. The private incentives of the EWG concern only the sale of power for compensation. The costs associated with voltage regulation, frequency control, and reserves are external to the EWG, being borne by the utility. The EWG must be held responsible for its actions and their effects on the entire system. Tight coordination is the only way to "internalize" these externalities to an extent comparable to the vertically integrated utility.

The externalities associated with EWGs are manyfold. What will be the effects on the transmission system? What will be the effects on other facilities?

63/ OTA, supra at 12.

> For example, if a new generating unit is placed on a site, say 10 miles from an existing plant, it is likely that all circuit breakers at the existing plant will have to be changed at a cost running into millions of dollars.64/

In a vertically integrated utility, this is an internal decision. With an EWG, it is a cost external to the EWG that is imposed on the system, and if the problem is not solved in some way, severe economic damage can result.

The potential harm from not addressing the externality could be wildly disproportionate to the value of the incremental power supplied by the EWG. Small events in a system can cascade to substantial emergencies. The failure of one AC-DC converter in the Florida system resulted in a loss of power to 550,000 customers.65/

It was the 1967 New York City blackout that led to the establishment of regional reliability councils.66/ Now all large utilities in the 48 contiguous states are members of one of the nine regional reliability councils that form the North American Reliability Council (NERC).67/

The evolution of the modern electrical industry has shown

64/ Joe D. Pace, "Comments Prepared for the California Public Utilities Commission Workshop on Electric Generation Deregulation", July 3, 1981, p. 6.

65/ Joskow and Schmalensee, supra at 41.

66/ Linda Martinson and Thomas W. Loria, "The Transitional Bulk Power Market", Public Utility Fortnightly, November 26, 1987, p. 20.

67/ OTA, supra at 11.

that reliability is dependent upon greater coordination. Thus, both least-cost power and reliability require coordination. Any legislation such as S.406 must be judged on whether the new market configuration leads to greater or less coordination.

Most authors agree that if deregulation is to produce net benefits, it must include greater coordination, not less.[68/] Some advocate increased horizontal mergers.[69/] The effect of a deregulation proposal on coordination is probably one of the most important criteria for judging such proposals. As stated by the OTA:

> **The greatest challenge to increasing competition in generation ... is maintaining the high degree of coordinated planning and operation among bulk power system components. If coordination is not addressed with appropriate care, the system may experience increasing costs and decreasing reliability.**[70/] [emphasis in original]

The next section will consider the various aspects of coordination in a post-S.406 world.

IV. Competition and Coordination

As has been illustrated, both least-cost pricing and reliability require a high degree of coordination. This is because there are multiple products involved with the provision of electricity and serious externalities arise unless all

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68/ Joskow and Schmalensee, supra at 76, 77, 114.

69/ Martinson and Loria, supra at 23.

70/ OTA, supra at 15.

products and services are accounted for.

It has been argued that S.406 may result in a new class of entrants in the generation sector. What will this increased competition do to necessary coordination? First, it should be repeated that many observers believe that existing coordination is still not optimal and that additional efficiencies are still possible:

> Why are these short-run opportunities not being exploited? ... The size distribution of electric power companies is extremely skewed. There are a large number of very small firms and only a few large operating companies and holding companies apparently able to achieve all economies internally. Large numbers of diverse firms hinder comprehensive tight pooling agreements.[71]

A description of coordination requirements will illustrate the difficulties of coordination in the presence of many diverse, competing interests. First, consider the types of information that must be shared and developed by all members of a potential pool. There must be forecasts of peak loads and energy fluctuations. The pool must plan least-cost generating additions and transmission additions. There must be individual and combined estimates of fuel costs, generator heat rates, and forced outage rates. Generator unit operation and maintenance costs must be shared and efficient maintenance schedules implemented. Unit retirements, line ratings and fixed charges must be projected.[72]

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[71] Joskow and Schmalensee, supra at 83.

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For a tight pool, contractual arrangements must specify rights and obligations. Transmission access rights and capacity obligations must be stated. Then these activities must be compensated. Generation obligations and least-cost economy exchanges must be arranged and compensated. Unit commitments and spinning reserves must be assigned and a formula for compensation developed. Besides scheduling maintenance, the schedule must be worked into the compensation system.[73]

Under a competitive situation, the desire of a new entrant is to build the type of facility consistent with private incentives in the geographic location consistent with private requirements. How does this square with the required long run planning that requires forecasts of total system load, and a long range view of the optimal asset mix?

Economic dispatch requires that all generating plants be dispatched on the basis of incremental costs. This is necessary to produce least-cost electricity. The economic incentive of the EWG, on the other hand, is to keep running and selling kilowatt hours, regardless of whether another facility is producing at lower cost. Here there is a fundamental tension between private EWG interest and system wide optimization:

> It must be clear that unless generating units are dispatched in order of incremental running costs, enormous real economic savings are foregone ... However, if individual generating companies are free to offer such buy/sell prices

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72/ Casazza, supra at 18.

73/ Joskow and Schmalensee, supra at 71.

> as they choose, efficient dispatch will not result.[74]

Will EWGs be willing to accept economic dispatch? It is highly unlikely that economic dispatch will be effective under take-or-pay contracts since the utility will end up paying for EWG power whether it is the least cost source or not. Even if the EWG accepts economic dispatch, what response will actually be received when the system operator calls for a change in output from an EWG? What will be the effect of having several different owners of generation facilities having to respond to effect the change? Certainly the tension in these situations is much greater than for a vertically integrated system where that decision is internalized.

An EWG's primary objective is to sell KWH. The utility or utilities in a control area are responsible for keeping generation and load in balance at all times and in doing so, monitoring system conditions and controlling generation to achieve reliable and economic operation. EWGs cannot provide the monitoring and controlling services. At best, an EWG could be like a utility-owned facility and contribute to tieline and frequency control, etc., _if_ its operation were under the direct control of system operators in a control area. If the operation of an EWG is controlled by contract or depends on an EWG's willingness to respond to requests for changes in dispatch, the current level of flexibility that exists at modern control centers will be degraded. Voltage regulation is an extremely important service. Since there is no explicit market for voltage regulation, an otherwise internal decision can only be forced by contract. Yet an EWG does not value voltage regulation at anywhere near the value placed on voltage regulation by the system. Therefore, contracts in this area will be difficult to monitor and enforce.

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[74] Pace, _supra_ at 4.

The types of coordination required are antithetical to competition. Imagine asking a group of competitors for the same customers to jointly plan who builds/owns facilities and where they are to be located. Imagine a group of competitors trying to agree whose facilities will shut down (with subsequent financial loss) so that the overall system will minimize costs. Imagine a group of competitors sharing the highly sensitive, internal company information necessary to arrive at such decisions. Imagine the Justice Department allowing them to share such information. Then construct a situation where some activities are compensated and others are not explicitly compensated. It is in every competitor's interest to get "the other guy" to do the uncompensated chores.

Contrast this to a situation where an integrated unit makes these decisions internally. Add one more factor. The competitors assigned to such noneconomic chores as spinning reserves and voltage regulation are under no statutory obligation to serve. It is absolutely in their self-interest to avoid such chores.

Many commentators consider competition and coordination to be at odds:

> There are in fact at least two inconsistencies or tensions inherent in this continuum: (1) that there may be a fundamental inconsistency between effective coordination and pooling and effective bulk power supply competition; and (2) a more subtle implication that there exists a trade-off between price competition and cost minimizaton...75/

Competitors will not want to share vital information. Diverse companies with different sizes; time horizons; corporate and financial structures; some governed by the obligation to serve, some not; some regulated, some not, will find it very difficult to agree on the myriad of things needed for effective pooling. Thus, "in deregulated environments in which coordination and pooling would involve potentially competing firms, there is every reason to believe that coordination and pooling would be less extensive and effective than at present."76/

A fundamental tension exists. Further economies can be gained by further coordination. Such coordination is possible with large, vertically integrated firms. It is extremely difficult with competing firms and even if ways could be found, they probably would not pass antitrust muster. For coordination to occur at all in the face of prevalent externalities and wide divergences in the private interests of individual companies and

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75/ Martinson and Loria, supra at 23.

76/ Joskow and Schmalensee, supra at 57.

the social interests of the entire system, very complex contractual arrangements would be needed. The economics of such arrangements, their effectiveness, and their relation to existing regulation, are discussed in the next section.

V. The Economics of Long-Term Contracts

A previous section has discussed the type of contracts that would have to exist between an EWG and a utility in a post-S. 406 era where EWGs account for a non-trivial portion of generation. This section will discuss the economics of such contracts in more detail.

Transaction Costs

A rich body of economic literature has developed over the last two decades that investigates the efficiencies associated with institutional and market structures and associated transaction costs. Much of the seminal thought in this area is attributed to Oliver E. Williamson. Of interest is whether economic decisions are more efficient if performed internally by one firm under an integrated structure or whether these decisions are better performed by competitive agents in a market structure. The interest is in economic efficiency and the analysis necessarily involves "comparative institutions," that is, the efficiency outcomes of differing structures. The most efficient outcome is one that minimizes transaction costs. According to Williamson, transaction costs hinge on three different items:

> [T]he three dimensions for describing transactions

> that are of special importance to transaction cost economics are (1) the frequency with which they occur, (2) the uncertainty to which they are subject, and (3), the degree to which they are supported by investments in durable, transaction specific assets. A considerable amount of explanatory power turns on this last.77/

These three items are said to affect the magnitude of costs as follows: costs are higher the less frequent are transactions (long-term contracts), costs are higher the more uncertain are the informational aspects, and costs are higher the more the transactions are related to an asset that has only one use and is not transferable.

Here, transactions costs do not refer solely to the costs of lawyers or negotiators. Rather the major costs are associated with risks that agreements will not be kept, that performance will be substandard, or that other resources will have to be committed to ensure expected performance. The greatest risk is that for infrequent, uncertain, asset-specific contracts one party or another will behave in an opportunistic fashion once the contract is "locked in".

Each one of the three items mentioned by Williamson has particular relevance for an electric power industry that involves competition for one product, generation, in a multi-product setting. Consider first, the concept of asset specificity. There are four aspects of a transaction that determine how asset-

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77/ Oliver E. Williamson "Vertical Integration and Related Variations on a Transaction Cost Economics Theme" Center for the Study of Organizational Innovation, University of Pennsylvania, Discussion Paper #129, April 1982, p. 5.

specific it is. Assets can be site specific, that is, they are constrained to be in a geographically limited area and are basically immobile. Such is the case for electric generators as opposed to, say, airplanes. Assets can be "physical asset-specific" meaning that they can be used only for one distinct purpose. Generators can only be used for producing kilowatt hours where, for instance, a stamping plant can be retooled to produce many metal products. Assets can involve a large amount of "learning by doing" where enormous experience is necessary to coordinate and operate efficiently. This is clearly the case with electric power. Finally assets can be dedicated to supplying one customer, as would be the case with an EWG.[78/] Thus the assets employed by an EWG contain all the elements of asset specificity and are, in fact, extreme examples of asset specificity. This is, of course, true of electric power generation assets in general.

It has been argued that "[t]he main factor that is responsible for vertical integration from a transaction cost point of view is asset specificity. . ."[79/] High transaction costs generally result in a more efficient outcome from vertical integration than from attempting to account for decisions in a contract. At any rate, the policing mechanism of enforcing a contract through the threat of loss of business is impossible for

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[78/] These four criteria come from id. at 11.

[79/] id. at 10.

assets like electric generators:

> Inasmuch as the value of this capital in other uses is, by definition, much smaller than the specialized use for which it has been intended, the supplier is effectively "locked into" the transaction to a significant degree. This is symmetrical, moreover, in that the buyer cannot turn to alternative sources of supply and obtain the item on favorable terms. . .[80]

The other two elements of high transactions costs are also present in potential EWG/utility contracts. Contracts would be extremely infrequent, generally life of facility take-or-pay contracts. Also, there would be enormous uncertainty concerning load, energy costs, etc., over the life of the contract.

Opportunism

Transactions costs are especially high for infrequent, uncertain, asset-specific contracts because of the possibility of opportunistic behavior. Such contracts are very difficult to enforce. Opportunism becomes the central focus of transactions costs in this context, especially when the transaction is asset-specific, as is the case with electric generation.[81]

Opportunism arises directly because of the "lock in" effect of long term contracting. Even if there is extensive competition prior to the signing of a contract, once the contract is signed, the future course of events is uncertain and "the contractual arrangement between buyer and seller is effectively transformed

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80/ Oliver E. Williamson "Transaction-Cost Economics: Governance of Contractual Relations", Journal of Law and Economics, October, 1979, p. 240.

81/ id. at 234.

into one of bilateral exchange." In such an exchange, both parties realize that the other is completely dependent. With litigation extremely costly, one party or another may attempt to extract extra-normal rewards from the other party. In the view of one group of commentators, it is the supplier of the essential service that is most likely to engage in opportunism.[82]

The two parties to the agreement have different incentives (their own self-interest). The dichotomy in interest produces a situation akin to a "moral hazard problem [which] arises because of the conjoining of inharmonious incentives with uncertainty."[83] Not all uncertainties can be captured in contingent contracts and "each party will be inclined, when unanticipated events occur, to manipulate the data in a way that favors its interests."[84]

Opportunism is difficult to guard against because litigation is costly and time consuming. In fact, "the threat of production delay during litigation may be an effective bargaining device."[85] Even if litigation is successful, "it is important to remember that financial penalties for failure to provide capacity will not keep the lights on."86/

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[82] Benjamin Klein, Robert G. Crawford and Armen A. Alchian, "Vertical Integration, Appropriable Rents, and the Competitive Contracting Process," Journal of Law and Economics 1978, p. 300.

[83] Oliver E. Williamson, Markets and Hierarchies, (The Free Press, New York 1975), p. 84.

[84] Oliver E. Williamson "Franchise bidding for natural monopolies -- in general and with respect to CATV." Bell Journal of Economics, Spring, 1976, p. 79.

[85] Klein et al. supra at 301.

Opportunism results in costs beyond litigation or loss of service. Long-term contracts are, by definition risky and may result in utilities having to devote real resources to protect against downside risks. It has been suggested, for instance, that reserve margins would have to be increased in a competitive environment in order to provide the same level of system reliability.

Long-Term Contracting Difficultues

Because of the possibility of opportunism, contracts between EWGs and utilities would be extremely complex and "[f]unctions now routine to utilities would increasingly have to be unbundled and established by contract or other agreements."87/ Short term, spot market contracts are efficient and self-policing for frequent transactions but are seriously defective for asset specific transactions such as electric generators,88/ because "a leading reason to make the contract long term is to provide the supplier with requisite incentives to unstable long-lived assets."89/

Contracts will be take-or-pay and most likely will require

86/ Casazza supra at 20.

87/ OTA supra at 15.

88/ Williamson (1979) supra at 241.

89/ Williamson (1976) supra at 81.

either risk premium payments or cost escalator clauses. "If the environment is characterized by uncertainty with respect to technology, demand, local factor supply conditions, inflation and the like, price-cost divergences and/or indeterminacies will develop."[90] This is, of course, exacty the situation that will occur with independent generation.

Contracts will either have to be "complete contingent" or incomplete contracts. The former are extremely difficult and costly to write, and the latter rely on good will. Sometimes premiums have to be paid to reinforce this "good will." The more specialized the asset, the greater the cost of either explicit or implicit contracts.[91]

Thus, highly complex, uncertain contracts would be necessary between EWGs and utilities. One group of writers has stated:

> Investments in electric power supply facilities have many of the characteristics that Williamson identifies as leading to internal organization (vertical integration) or complex long-term contracts. Where segments of electric power systems must be limited by contract rather than internal organization. . . complex long-term contracts will emerge. There is no guarantee that such contracts will lead to more efficient outcomes than internal organization.[92]

The OTA agrees with this assessment:

> [C]ontracts may have some shortcomings when compared to arrangements within a single organization, as in a vertically integrated utility. For example, given

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[90] id. at 82.

[91] Klein et al. supra at 303.

[92] Joskow and Schmalensee supra at 126.

> the overall uncertainty in the power industry, anticipating all terms and contingencies requires extensive effort.[93]

Vertical Integration Versus Long-Term Contracting

The first point that must be made is that the extraordinary costs associated with the types of long-term contracts needed in a post-S. 406 world result in an outcome inferior to vertical integration. In fact, "[t]he prohibitive cost of such contracting is what explains the decision to integrate."[94] In a natural world, "[t]ransactions that are supported by investments in durable, transaction specific assets are ones that experience 'lock in' effects, on which account autonomous contracting will commonly be supplanted by unified contracting (vertical integration)."[95] Students of industrial organization agree that vertical integration is the most efficient organizational mode for asset specific, uncertain investments of the type of concern here.[96] This is because the "costs of contracting will generally increase more than the costs of vertical integration."[97]

Similarities Between Regulation and Long-term Contracting

If long-term contracts are less efficient than vertical integration in cases similar to electric power generation, then a second point is in order. The types of contracts that would be necessary in a non-integrated situation are virtually identical to government regulation.

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[93] OTA *supra* at 15.

[94] Williamson (1975) *supra* at 85.

[95] Williamson (1982) *supra* at 6.

[96] *id*. at 10.

[97] Klein et al. *supra* at 298.

Senator Johnston has criticized the existing regulatory compact:

> In general terms, cost-of-service regulation may create a poor match of risk to reward because it gives utilities a chance of recovering all costs while eliminating the possibility that gains from increased productivity can be kept. Conversely, cost-of-service regulation can be used by regulatory commissions as an arbitrary device for heaping all risks on utilities.[98/]

As Williamson points out, however, "before regulation is supplanted, there is an obligation to assess the properties of the proposed alternative."[99/]

With respect to long-term contracts under competitive situations, Williamson argues as follows:

> [I]f the good or service is to be supplied under conditions of uncertainty and nontrivial investments in specific assets are involved, the efficacy of franchise bidding is highly problematic. Indeed the implementation of a franchise bidding scheme under these circumstances essentially requires the progressive elaboration of an administrative apparatus that differs mainly in name rather than in kind from that which is associated with rate of return regulation. It is elementary that a change in name lacks comparative institutional significance.[100/] [emphasis in original]

[98/] Johnston *supra* at 4.

[99/] Williamson (1976) *supra* at 73.

[100/] Williamson (1982) *supra* at 13, 14.

He points out that "technical standards by themselves, are not self-enforcing; enforcement requires that a policing apparatus be devised."[101] Further, quality evaluation will, most likely, be assigned to a specialized agency. "But again, the convergence toward regulation is noted."[102] Technical standards and quality coordination are extremely important for economic dispatch and reliability in the electric power industry.

Other commentators note the similarities between the type of contracts required in cases similar to a post-S. 406 world and regulation:

> Regulation of prices and entry has many similarities to the long-term contracts likely to emerge in a deregulated power system . . .
>
> The compensation arrangements under this type of contract have many similarities to the way in which regulatory commissions determine revenue requirements for the regulated utility.[103]

Who Bears the Risk -- the EWG or the Utility?

A key factor in this contractual analysis is that utilities are governed under a statutory obligation to serve while EWGs will not be. This, plus other factors, results in a situation where virtually all risk is shifted onto the utilities and/or rate payers. Even under contractual obligations, facilities may not be built. According to the OTA:

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[101] Williamson (1976) supra at 82.

[102] id.

[103] Joskow and Schmalensee supra at 127, 138.

> Even with contracts for the right facilities, there is some uncertainty that the facilities will actually be completed as required because the contractor could encounter problems and withdraw. Utilities also can misestimate costs, but they are unlikely to cancel a plant that is needed to meet their obligation to serve.[104]

In fact, if an EWG reneges on the building of a facility, it is the utility that will ultimately be held responsible for the needed capacity. So the utility bears the risks of default by an EWG. The long-term contractual arrangement also means that the utility will bear the operational risks. Life-of-facility, take-or-pay contracts with fuel escalator costs mean that the utility, not the EWG, bears the risk of sub-standard performance, inefficient production, and unexpected fuel price increases. Thus, with respect to risk, utilities and consumers will be in exactly the same position as under regulation and, "it is clear that a large fraction of the risks that consumers bear under current regulatory practice will be reflected in these unregulated long-term contracts."[105]

With utilities bearing all the risks of new EWG generation, it is no wonder that the financial structure of an EWG directly affects a utility's credit rating, as was discussed in Section II. If a utility develops an EWG in a highly leveraged setting, credit agencies will look directly through the financial structure of the EWG and implicitly or explicitly incorporate it in the utility's bond rating. This is also true for long-term contracts with independent EWGs. All risk must be accounted for somewhere and in this case it will be attributed directly to the utility's capital structure.

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[104] OTA *supra* at 19.

[105] Joskow and Schmalensee *supra* at 138.

There is already evidence of this flow-through effect. Even though utilities are in much better financial shape than a few years ago, bond ratings have not improved. According to the OTA:

> The industry's average bond ratings, for instance, have not improved over the past decade, primarily because ratings agencies believe that improvements in the industry's fundamental financial condition have been offset by increased business risk resulting from the growth of competitive forces and new regulatory approaches.[106]

VI. Energy Policy Issues

The OTA has noted:

> If new generating plans rely primarily on gas-or oil-fired turbines, and if the price of those fuels rise sharply, as they have several times in the past, electricity could become significantly more expensive.[107]

It is essential that a regional power system have a properly distributed "portfolio" of facilities employing different fuels to minimize the possibility of price shocks associated with fuel cost surprises. Accordingly, it is essential that the capital stock not be artificially skewed in favor of facilities using a specific fuel.

What are the energy economics of power generation? It is generally conceded that in terms of heat rates (BTUs/KWH), combined-cycle facilities have the lowest heat rates, coal-fired facilities the second lowest, and stand-alone gas-fired turbines the highest of the three.

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[106] OTA *supra* at 52.

[107] *Id.*, at 5.

Producing heat by use of gas is, however, more costly than by use of coal. The Energy Information Agency stated that in 1988 it cost $2.263 to produce a million BTUs by use of gas, but only $1.466 to produce a million BTUs by use of coal.108/

Assuming optimal technologies, fuel costs per kilowatt hour are 30-to-40 percent higher for a combined-cycle facility than for a coal-fired facility, assuming 1988 prices. Gas-fired facilities can only make sense if the relative advantage in capital costs outweighs the higher fuel costs.

There are two components of capital costs of interest here. The first is the measure of capital stock per kilowatt hour. The second is the artificial financial cost of capital advantages listed in earlier sections. A legitimate economic trade-off is between capital stock per kilowatt hour and fuel cost per kilowatt hour. If fuel costs were constant, and this comparison resulted in a favorable outcome for gas-fired technology, then society might be well served by relatively greater use of this technology. But if gas prices are volatile, then society should not rely on this technology.

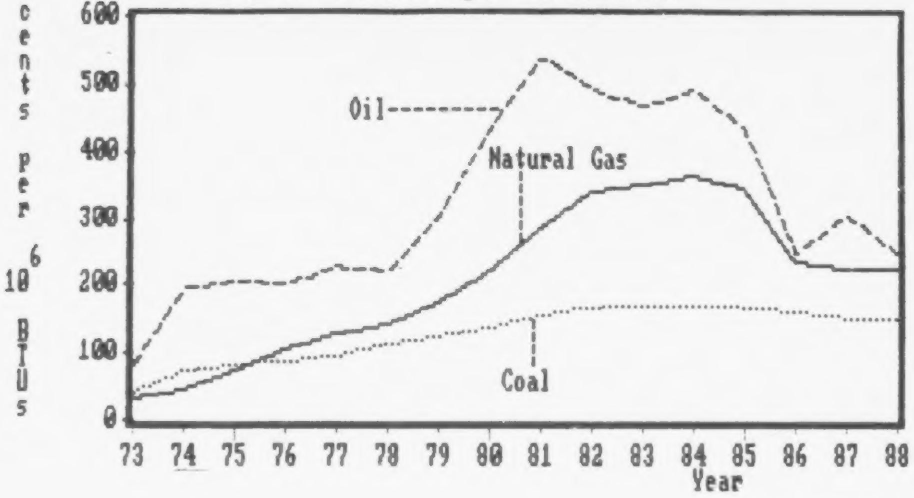
The problem occurs when it is the artificial financial cost

108/ Energy Information Administration, Cost and Quality of Fuels for Electric Utility Plants 1988, pp. 6, 7.

of capital advantage that puts the gas-fired technology over the top. To the extent that investment decisions are made on the basis of such artificial factors, there will be an inefficient, over-intensive reliance on this type of technology. The results will be a suboptimal mix of assets with respect to the fuels portfolio.

If the capital stock is artifically skewed towards gas-fired technology, problems could arise in the future. Figure 2 illustrates the basis of this problem by graphing the costs per million BTUs of coal, natural gas, and oil. Coal prices have been much less volatile and much more predictable than oil or natural gas prices. Thus, there is much greater risk associated with oil- or gas-fired technologies than for coal. Artificially distorted investments resulting in over-intensive use of gas-fired facilities magnify this risk.

FIGURE 2--Heat Equivalent Prices of Natural Gas, Coal, and Oil (in cents per million BTUs)



VII. Conclusions

- It is plausible to believe that after enactment of S.406, a new class of EWGs would successfully enter the bulk power market and supply a non-trivial portion of generation.
- This successful entry would not be due to any inherent superior efficiencies, technologies, or managerial skills, but rather to an artificial 20-to-30 percent cost of capital advantage based solely on the federal tax distinction between debt and equity. This advantage translates into an artificial price advantage of about 5 to 10 percent per kilowatt hour.
- This EWG price advantage is obtained only by imposing costs on utility shareholders and/or eventually the utility's ratepayers. Thus, true economic accounting would not accept the EWG price advantage as real.
- The utility/EWG arrangement would be based on long-term, life-of-facility, take-or-pay contracts, most likely with fuel cost escalator clauses.
- Long-term contractual arrangements that are highly uncertain and based on asset-specific investments are inferior, from a transactions cost standpoint, to vertical integration. Thus, the EWG/utility relationship is inferior, relative to the current vertically integrated utility system.
- The utility/EWG contractual relationship necessarily will look a lot like the current regulatory structure. Long-term, uncertain, asset-specific contracts converge to the appearance of rate of return regulation. Thus, no obvious efficiencies are to be gained by switching from current regulation to long-term contracting.
- The entire risk associated with EWG investment will be shifted on to the utilities and/or their rate payers.
- Further coordination in the electric power industry is necessary to achieve least-cost power and reliability. The unpredictable "competition" produced by S. 406 will lead to less coordination, not more. It is not likely, therefore, that S. 406 will lead to either lower cost power or greater reliability. In fact, most likely the converse is true.

- S. 406, in combination with capital minimizing strategies, may lead to an artificial over-intensive use of gas-fired technologies. This will erode the optimal fuels portfolio and lead to greater cost and energy uncertainty in the future.
- In the final analysis, there is an enormous amount of uncertainty concerning the effects of S. 406. There is nothing in the current analysis that predicts great gains from S. 406. Most likely, S. 406 will result in a system that is at least marginally less reliable and less efficient.

November 16, 1989

TESTIMONY OF THE ELECTRIC RELIABILITY COALITION BEFORE THE SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES
ON
THE COMPETITIVE WHOLESALE ELECTRIC GENERATION ACT OF 1989
S. 406

INTRODUCTION

The Electric Reliability Coalition (ERC or the Coalition) respectfully submits these comments in opposition to S. 406, the Competitive Wholesale Electric Generation Act of 1989. The recently formed Coalition represents a large and diverse group of investor-owned, regulated utilities located in every region of the United States.[1] ERC's position is presented in behalf of a group that now includes 19 of the nation's 50 largest investor-owned utilities (IOUs), as measured by sales of kilowatt hours, who produce over 30 percent of the electric power generated by IOUs in this country.[2/] The balance of ERC's 38 members are smaller companies, including several whose primary service area is limited to a single metropolitan area.

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[1] Current ERC members are: Carolina Power & Light Co.; Centerior Energy Corp. (including Cleveland Electric Illuminating Co. and Toledo Edison Co.); Central and South West Corp. (including Central and South West Services, Inc., Central Power & Light Co., Public Service Co. of Oklahoma, West Texas Utilities Co., and Southwestern Electric Power Co.); Central Hudson Gas & Electric Corp.; Commonwealth Edison Co.; Detroit Edison Co.; Empire District Electric Co.; Florida Power & Light Group, Inc.; Florida Power Corp.; Gulf States Utilities Co.; Houston Lighting & Power Co.; Iowa Public Service Co.; Iowa Power & Light Co.; Kansas City Power & Light Co.; Kansas Gas & Electric Co.; Madison Gas and Electric Co.; Minnesota Power Co.; Northern Indiana Public Service Co.; Oklahoma Gas and Electric Co.; Pennsylvania Power & Light Co.; Potomac Electric Power Co.; Philadelphia Electric Co.; Public Service Co. of Colorado; South Carolina Electric & Gas Co.; Southwestern Public Service Co.; TECO Energy, Inc.; Texas Utilities Co.; Union Electric Co.; Vermont Yankee Nuclear Power Corp.; Wisconsin Electric Power Co.; and Wisconsin Public Service Corp.

ERC members also represent a diversity of fuel use. Some of our member companies are heavily coal-based. For example, at least two companies utilize coal for some 90 percent of their energy requirements.[3/] A few burn large amounts of natural gas, with at least three companies deriving over 40 percent of their energy requirements from gas. Seven ERC members rely on nuclear facilities for at least 20 percent of their power. Several rely on significant amounts of purchased power, including two companies that purchase at least a third of their power from other sources.

SUMMARY OF COMMENTS

ERC members share a deep concern about the adverse impact of S. 406 and similar proposals on the national goal of continued adequate supplies of electric power at reasonable cost to our customers. The electric power industry consistently has

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[2/] For the twelve months ended September 30, 1988, total sales by these 19 ERC companies were 681.6 billion kWh. This was over 37% of total sales during that period by the top 50 IOUs, and slightly more than ~~30% of~~ total sales of all IOUs for that period. See Arthur Andersen & Co./Cambridge Energy Research Associates, Electric Power Trends at 82 (1989 ed).

[3/] Energy sources for the 50 largest investor-owned utilities, including 20 ERC companies, are set forth in the Arthur Andersen/CERA report, *supra,* at 86.

fulfilled its obligation to serve all customers with adequate, reliable and reasonably priced electricity. As an industry, we have provided exemplary service, despite difficult and sometimes unpredictable circumstances. The vertical integration of our companies and concomitant coordination of service among them, carried out under a system of complex regulation and voluntary cooperation, has provided electricity users this efficient and reliable service. Economists say that additional savings to the consumer can be realized through greater coordination, not less. Even the Federal Energy Regulatory Commission's Transmission Task Force agrees.

By contrast, Exempt Wholesale Generators (EWGs) will flourish by "riding on" the equity of the regulated utilities to which they sell power. EWGs will exist because of artificial tax advantages, not inherent economic or technical efficiencies. Moreover, these new entities could prove to be very difficult and costly for utilities to integrate into their systems without jeopardizing reliable service.

It will be extremely difficult, if not impossible, for state utility regulators to account for the true costs to a utility of purchasing EWG power, in terms both of increased cost-of-capital and of additional costs to manage reliably the EWG power. As a result, EWGs in some cases may appear to be able to sell power at lower prices than projected future costs of some utilities for baseload plants. If utilities are compelled nevertheless to purchase this power through state prudency reviews, as is all too likely, the utility's consumers ultimately will pay the price for these illusory bargains.

Another effect of S. 406, whether or not intended, could well be to enable EWGs to undersell rates to existing wholesale customers of regulated utilities, or possibly even to make sales to large industrial customers through brokers or municipalities. These transactions would be facilitated by the new rights of transmission access and wheeling that EWG developers undoubtedly would seek in the wake of this bill, if it were enacted. By and large, these customers are now being served by regulated utilities that have committed large investments to provide that service over the long term. The costs of these "stranded investments" would have to be recovered from the remaining retail consumers, through higher electric rates.

ERC counsels strongly against piecemeal legislation in this critical policy area. Proponents of S. 406 attempt to minimize its significance as simply removing an unnecessary "obstacle" to further development of independent power producers (IPPs). But the bill's narrow scope, as written, does not mean that its application would not likely produce great harm. By removing the PUHCA "obstacle" to widespread development of independent power production facilities, Congress could set in motion an avalanche of decisions and events that could jeopardize the long term future of the nation's electricity supply. PUHCA "reform" would set the stage for placing substantial amounts of future electric generation capacity outside the direct jurisdiction of the states and under the jurisdiction of the Federal Energy Regulatory Commission, at least some members of which appear inclined to dismantle the fundamental principle of cost-based regulation[4/].

This "technical amendment" to the Holding Company Act would ignore overarching policy issues of domestic and even global significance. For example, how can Congress responsibly commit the nation to the path of non-regulated independent power generation without concurrently considering the consequences of laws that have been or will be proposed to deal with the issues of acid raid and global warming, which will have profound impacts on utilities' costs? How can Congress support a system whereby small facilities not subject to current (or perhaps future) air pollution controls can, in the aggregate, put out enormous quantities of atmospheric pollutants exceeding those that would be released from a utility-owned-and-operated plant of comparable capacity? How can Congress give a green light to FERC to restructure the electric power industry without considering alternative policies that would foster construction of capacity by regulated utilities, such as recovery of costs associated with construction work in progress and development of cost-effective

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[4/] Whether FERC will proceed to finalize its 1988 Notices of Proposed Rulemaking regarding IPPs and bidding procedure is unclear at this time. However, it would matter little whether FERC abandoned Federal Power Act regulation of EWGs' sales by changing its rules or through case-by-case proceedings. The end-point would be a new class of substantially deregulated wholesalers of power, whose raison d'etre is to supply power to franchised utilities (or, conceivably, to a select portion of their retail customers).

nuclear licensing procedures and technologies? Similarly, if Congress facilitates independent power production by amending PUHCA, the question of transmission access inevitably and immediately will arise in the legislative or regulatory arena. Transmission access issues are directly involved in S. 406, whether or not there are any provisions in the legislation dealing with this issue. ERC strongly believes that Congress should not ignore this fundamental issue, nor simply cede to the FERC basic policy decisions that are critical to the nation's future.

For all these reasons, ERC opposes S. 406.

DETAILED COMMENTS

1. There is No Crisis That Would Justify Precipitous Action By Congress.

The electric utility industry has an outstanding record of service and efficiency. The key question this Committee must address is whether it is worth gambling the nation's energy security on hoped-for, but unfounded, advantages of "competitive" power generation. The United States' highly reliable electric power service universally is taken for granted. What is less appreciated is our steady improvement over many years in assuring least-cost service that also meets the reliability standards our nation's electricity consumers need and deserve. It is no accident that this dual goal has been achieved through increased coordination among vertically integrated entities. As the recent report of FERC's Transmission Task Force observed:

> The industry has made great strides during the past three decades in developing robust transmission grids and coordinating their planning and operations to save American consumers tens of billions of dollars a year.[5]

The Task Force recognized that great economies are achieved through interconnection, coordination and pooling, including both long-term economies arising from the sharing of reserves and short-term cost savings resulting from efficient dispatch so as to generate needed power at the lowest possible cost. Indeed, the Task Force called for even greater coordination, especially among smaller utilities, so as to realize a projected 15 percent additional savings to the consumer.[6]

As a result of efficient, coordinated and reliable operations by the utility industry, electricity is a bargain in the United States. According to the Energy Information Administration, during the period 1980-1987, the average price for residential electricity in the United States was about 14 percent less than in all industrial countries, while the average price for industrial electricity was almost 8 percent less.[7]

5/ Federal Energy Regulatory Commission, The Transmission Task Force Report to the Commission: Electricity Transmission: Realities, Theory, and Policy Alternatives. (Oct. 1989) at 21.

6/ Id. at 22-23. This is consistent with a Department of Energy study conducted in 1980 that concluded that full integration of utility systems is necessary to achieve the lowest costs. Power Pooling: Issues and Approaches, Washington, D. C. (Jan. 1980) at 4.3-4.8.

7/ Electrical World (July 1989) at 36.

Some critics of the industry's performance point to the fact that the inflation-adjusted price of electricity increased 27 percent between 1970 and 1985. But this increase -- an annualized increase of only 1.8 percent -- coincided with a period of severe financial shocks to the industry. These included previously unimaginable oil prices, followed by unprecedented interest rates, new requirements for environmental controls, and costly changes in regulatory requirements for new baseload plants. Despite the dislocations and adjustments caused by these unforeseeable and largely uncontrollable events, the nation's electric utilities consistently have met their obligation to serve.

Some supporters of amending PUHCA have questioned whether the utility industry is planning properly for the new generating capacity that will become necessary in the mid-1990s. The Coalition believes that the industry is committed to planning and building new generating capacity as it is reasonably required. We recognize that there may be additional potential for conservation and load management improvements.

While there may exist localized situations in which capacity shortfalls appear possible in the 1990s, primarily in New England, these situations are not representative of conditions elsewhere. The overall national picture is one of an industry with adequate capacity responsibly planning for future capacity needs throughout the country. One major reason that new large baseload plants are not now under construction by utilities is that the load curve of many utilities shows that demand can most economically be met in the near term by smaller units for peaking capacity. Certainly, there is no need fundamentally to restructure the electric industry nationally in order to address capacity shortfalls that may occur only on a few utilities' systems. This is particularly so where the thrust of the restructuring is to increase reliance on largely gas-fired, unregulated third-party generators that have no service obligation and are financed with high debt-to-equity ratios. Moreover, less risky options could be instituted at the federal or state levels to remove localized impediments to planning and construction of additional capacity.

2. EWG "Competition" Will Not Produce Lower Electricity Costs.

A. Facilitating EWG Entry Into The Electric Power Business Will Not Result in Genuine Competition.

It is often presumed that consumers of goods and services inevitably benefit from markets in which competition exists. In many, if not most, instances that is true. But, the entry of EWGs into the business of generating electric power cannot be equated with "competition," at least as economists use that term.

Competition benefits consumers by increasing the supply of goods or services, or by introducing new or improved goods or services, or by ensuring that goods or services are produced as efficiently as possible, thereby reducing their prices to consumers. ERC does not believe that any of these benefits, at least over the long term, would result from the entry of EWGs into the generation business. This is because EWGs are unlikely to possess any true competitive advantages over regulated utilities as power producers.

Instead, EWGs probably will be able to enter the marketplace only by virtue of an artificial cost advantage attributable to the favorable treatment of highly leveraged entities under the federal income tax laws. This leveraging will be possible only to the extent that contracts with purchasing utilities are assured, e.g., long-term take-or-pay contracts. Through the regulatory process, EWGs may well succeed in obtaining such contracts, thereby shifting risks and costs to the utilities that buy power from them. Transfer of these risks to utilities will increase their cost of capital, which will result in higher prices to the consumer. "Competition" of this sort would not be genuine, effective competition and would not reduce costs to electricity consumers. In this setting, discussions of "competition" and its benefits are misplaced.8/

8/ Supposed analogies between the electric utility industry and other industries that have been "deregulated" are fundamentally flawed. For example, proponents of S. 406 may seek to draw parallels between electric service and telephone or natural gas service. However, each of those industries is quite different from electric service. Neither telephone companies nor natural gas companies are obligated to have systems that can meet instantaneous peak demands. Indeed, it is not uncommon at peak demand periods for both gas and telephone service to be interrupted,
(Continued)

B. EWGs' Artificial Cost-of-Capital Advantages

EWGs are unlikely to be more efficient power plants. Power plant design and construction is fairly standardized, and gas-fired generation does not involve innovative technology. Methods of operation likewise are uniform. The upshot is that there does not appear to be any significant technological or other inherent advantage available to independently owned and operated generation facilities.

Nevertheless, some EWGs may be able to sell power at rates apparently lower than the projected future costs of utility baseload generation. This will not be the result of superior technology, management or operating skills. Rather, any apparent pricing advantage of an EWG more likely will be due to an artificially lower cost of capital (and to the fact that the EWG will shift to the purchasing utility certain associated risks and costs). Existing utilities employ a large proportion of equity

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curtailed or otherwise unavailable. Moreover, the natural gas industry is able to store gas in order to balance supply and demand, whereas in an electric utility system generation must match load exactly at every instant in time.

The electric utility industry is already substantially more decentralized than is the telephone industry, even after the breakup of AT&T. In the "deregulated" telephone industry, local telephone service is provided by a handful of regional monopolies that have no competitors. Finally, in neither the natural gas nor telephone industries has deregulation permitted new entrants into the business to enjoy artificial "competitive" advantages due to highly-leveraged financing and the transfer of risk to pre-existing suppliers.

in their capital structures.[9] This is in contrast to the probable financial structure of the new crop of EWGs. Most observers believe these entrepreneurial ventures will be highly leveraged, with equity of 10 percent or less. Of course, the federal tax code and most state tax laws treat debt more favorably than equity. (This is because interest is tax deductible, while dividends are not.) As with any highly leveraged company, the marginal effective tax rate for these EWGs will be substantially less than for a company whose capital structure has a higher equity component, and the EWGs' effective cost of capital therefore will be correspondingly less.

An economic study prepared for ERC concludes that a highly leveraged EWG could enjoy a 20 to 30 percent cost-of-capital advantage over an existing utility with a traditional capital structure. This artificial cost of capital advantage would allow an EWG to price electricity an estimated 5 to 10 percent lower than could a utility.[10]

A regulated utility probably could not simply establish an EWG to compete on even terms with these tax-favored entities. A highly-leveraged subsidiary (even when financed with non-recourse debt) could adversely affect the parent utility's debt-equity ratio and bond rating and thereby increase its cost of capital.

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[9] In 1987, on average, 49.4% of utility capital was equity.

[10] D. Raboy, "The Economic Effects of S. 406," at 11-19 (unpublished; November 6., 1989). A copy of this study is being submitted to the Committee for inclusion in the record.

This of course, would nullify the tax advantages of the utility EWG's leveraged financing.[11]

C. Additional Costs Of Relying on EWG Power

Proponents of S. 406 argue that it would do no more than provide regulated utilities with an "option" to purchase EWG power. As a practical matter, however, utilities may have no real alternative but to buy EWG power, even though it is not really economic in the long term to do so. Indeed, ERC foresees that utilities will come under irresistible pressures from consumers and regulators to buy the apparently cheaper power offered by EWGs, in lieu of investing in rate-base facilities to generate needed power or purchasing it from other non-EWG utilities.

These pressures will result because it is difficult for state public utility commissions to determine, in the course of prudency reviews or other regulatory proceedings, what would be the true costs and benefits to the regulated utility of purchasing power tendered by EWGs. State regulators have had great difficulty ascertaining the "avoided cost" of utility-generated power for purposes of setting rates to be paid cogenerators under PURPA. In Texas, for example, regulators have required Houston Lighting & Power Co. to pay cogenerators capacity charges of as much as $230/kw/year, based on the cost to the utility of building a lignite plant, when the utility could construct the same type of combined cycle gas turbines used by the cogenerator at a cost of only $35/kw/yr, calculated consistent with the QFs' capacity payment.[12] As a result, that company's customers paid, in 1988 alone, $150 million more for QF power than they would have if Houston Lighting & Power had constructed identical natural gas turbines to serve the load.[13]

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[11] *Id.* at 19.

The Texas experience is not unique. When California regulators initially implemented PURPA, they instituted a "standard offer" to be paid to QFs. The standard offer overstated significantly the actual avoided cost to purchasing utilities, and was modified. However, this adjustment occurred only after California utilities and their rate payers had, under compulsion, purchased millions of dollars worth of power at uneconomic prices. Again, ascertaining "avoided cost" with precision proved very difficult.

There is no reason to expect that state commissions will be any better able (or willing) to gauge the true cost to a regulated utility of EWG power when reviewing the utility's decision to construct new capacity (or use existing plants), or to purchase power from other utilities, to meet demand.[14] Again, the benchmark will be the utility's supposed "avoided cost." Any utility that declines to purchase proffered EWG power will do so at its peril, knowing that its state commission may disallow any investment or purchased power costs that exceeds the nominal price of that EWG power.

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[12] Written comments of D. D. Sykora, President and Chief Operating Officer, Houston Lighting & Power Company, before the House Subcommittee on Energy and Power (Sept. 22, 1989) at 2.

[13] Statement of L. G. Brackeen, Houston Lighting & Power Company, Before Strategic Issues Subcommittee of the NARUC Electricity Committee (Oct. 30, 1988) at 2.

In fact, the stated price of the EWG capacity often may appear to compare favorably with the incremental cost to a utility of generating that power in future baseload plants.[15] At the outset, the EWG may have a price advantage of up to 10 percent due to its cost-of-capital advantage. Failure in the regulatory process to offset the EWG's price advantage by an amount reflecting the utility's increased cost-of-capital due to transferred risks would understate the true cost of EWG power.

In addition, a utility that relies on significant amounts of EWG power would incur some other significant costs that will be hard for regulators to quantify, but are no less real. Utilities do not merely generate and sell kilowatt hours. They perform a group of interdependent and complementary services essential to a reliable electric supply. These services include voltage regulation, frequency control, and the provision of spinning and other reserves. EWGs would have no financial interest in providing these services. If the utility buys EWG power, it will become more costly for the utility to continue to provide these services itself. These costs will reflect, in a variety of ways, the loss of efficiencies formerly resulting from vertical integration and from inter-utility coordination.

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[14] Even assuming that state regulators can identify and quantify all costs to a utility of purchasing EWG power, it is not inconceivable that they may find it more expedient to take actions that appear to give rate payers a short-term benefit, i.e., requiring the local utility to purchase EWG power at lower nominal prices.

[15] Of course, even if the apparent EWG price advantage of 5 to 10 percent represented a genuine savings to the purchasing utility, the savings to the consumer would be substantially smaller. Assuming that a utility bought EWG power for 25 percent of its energy requirements (a large proportion), system supply costs would be only 1.25 to 2.5 percent less than if the EWG power were instead self-generated or obtained from other utilities.

As explained in more detail in the following sections, there are substantial costs attached to a utility's loss of control over the siting, design and operation of generation units on its system. Even well-intentioned and sophisticated state regulators may be unable adequately to quantify these "negative avoided costs." There would be serious potential for miscalculation leading to compulsory, but uneconomic, purchases of EWG power.

(i) Additional Costs Of EWG Siting Decisions

Proliferation of EWGs could undermine effective utility control over the siting of generation units and system planning, creating both immediate and continuing higher costs to the utility. Currently, individual states and their franchised electric utilities share responsibilities for determining the general location, size, and type of power generation facilities. Planners consider proximity to load centers, environmental concerns and transmission line requirements.

Especially in large service territories, generation is dispersed geographically so as to provide needed reserves throughout the system and to minimize the need for additional transmission.

Non-utility generation facilities will often tend to be sited to minimize the EWG's costs, with the developer's needs taking precedence over the utility's where they are not consistent. Capacity that is not in the correct location has less value to the franchised utility than do properly sited units, because the utility must have greater reserves elsewhere on the system than otherwise would be needed for reliability and economy. The costs that the purchasing utility could avoid by purchasing EWG power would have to be adjusted to reflect the costs arising from sub-optimal siting -- a difficult exercise that state commissions may be unable adequately to undertake. 16/

(ii) Additional Costs of EWG Design Decisions

Utility-owned and operated generating facilities are designed and constructed for the best combination of reliability

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16/ State commissions may find it unattractive to attempt to quantify all of a utility's costs resulting from EWG power purchases due to the fact-dependent nature of the controversies that will arise. For example, it is known that if an EWG were sited too close to an existing power plant, circuit breakers would have to be changed in the existing plant, at a cost to the utility of millions of dollars. See J. D. Pace, "Comments Prepared for the California Public Utilities Commission Workshop on Electric Generation Deregulation" at 10 (unpublished; July 3, 1981). However, determining the exact amount of these and numerous other modifications to the utility system would no doubt be a hotly contested issue in any regulatory proceeding. State commissions would find themselves embroiled in even more contentious proceedings than those involving rates for purchases from QFs under PURPA.

and economy. This entails an appropriate level of redundancy in many components, such as valves, boiler feed pumps, fans, etc. For this reason, the capital costs of utility-constructed units may be higher in the short term than the bare minimum costs for which a facility of the same capacity and fuel type could be built by an EWG entrepreneur. Over the long term, however, these redundancies reduce costly outages and maintenance.

Non-utility generating ventures are likely to be highly leveraged projects. They may well be designed to minimize front-end capital costs, as evidenced by the anticipated strong preference for gas-fired turbines or combined cycle facilities. EWG developers may be far more likely than would a utility to trade off reduced initial capital costs against possible future revenue losses due to outages or to increased maintenance costs. When proffered power from such a facility, the utility may well need to recognize that it will have to compensate for potential reduced reliability by procuring some additional reserves that would not be necessary if the power were generated by the utility itself. However, will state regulators likewise recognize this need and fully account for the additional cost to the utility?

(iii) Additional Costs of EWG Operating Decisions

EWGs may have economic incentives to resist centralized utility control and dispatching of their generating units. Such control is crucial to ensuring correct regulation of voltage, balancing of loads and maintaining adequate reserves at all times. A production/transmission/distribution system must obey the laws of physics at every instant. Every component of the system, at every moment, is dependent on every other component. The failure of even a small, isolated component can require redistribution of generation or some other operating procedure to be implemented to prevent damage to facilities or a system-wide failure. As such, the entire system is hostage to each of its elements.[17/] The result of poor coordination can be disastrous for reliability:

> Generating plants connected to the same power system cannot operate independently of one another. This is a physical impossibility. Unless generation in the aggregate matches load, on a second-to-second basis, large scale outages may occur, and damage to generation and transmission assets is likely.[18/]

In a vertically integrated system, or in a pool involving even relatively few vertically integrated utilities, maintaining reliability is a complex process that requires great cooperation and constant vigilance. Under the traditional arrangements of voluntary cooperation among regulated suppliers, all of the affected participants have a common interest in performing their

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[17/] For example, north-south transmission lines within the Electric Reliability Council OF Texas system, originally built solely for reliability, are now carrying substantial power attributable to increased generation on ERCOT members' systems. These lines have little reserve capacity and could become overloaded if even one generating unit turned out not to be effectively interruptible in the event of a system emergency.

[18/] P. L. Joskow and R. Schmalensee, Markets for Power at 113 (1983).

legal obligation to serve. By contrast, EWGs will be concerned only with the maximum sale of kilowatt hours. The independent producer who is maximizing energy sales will have a financial incentive not to submit to utility dispatching, thereby shifting to the utility the costs of providing the essential services of maintaining spinning reserves, voltage regulation, etc.

Difficulties in dispatching EWGs could also preclude the utility from achieving the least-cost mix of generation that generally exists today. Centralized control of generating units is necessary for economic dispatch, *i.e.*, dispatch of units on the basis of incremental costs, consistent with reliability. It is only through absolute control of the maintenance and operation of the system by a single entity, whether it be the utility or a shared control center, that reliability and least-cost dispatching can be assured.[19] However, an EWG whose sole economic motivation is to sell energy will be unreceptive to a utility dispatcher's request to interrupt its output so as to maintain non-revenue producing "spinning reserves," control voltage, or respond to a system emergency. Similarly, an EWG may set relays so as to minimize wear and tear on its own generators, to the detriment of the utility's equipment. Thus, EWGs are likely to stand in an adversarial relationship to the purchasing utility, in contrast to the reciprocal obligations and cooperation that characterize inter-utility operations today.

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[19] As the Congressional Office of Technology Assessment has observed:

> "To minimize operating costs . . . ., centralized control of dispatch or other mechanisms to select lowest cost of generation must be established."

Electric Power Wheeling and Dealing: Technological Considerations for Increasing Competition at 18 (May 1989).

In short, a breakup of the integrated utility system would decrease efficiency in utility operations. Regulated utilities of course would continue providing the bundle of services -- generation, transmission, distribution, voltage and frequency control, provision of reserves, etc. -- that the American consumer needs for reliable service. But this service will cost more if regulated utilities buy power from many independent self-interested generators rather than producing the power in integrated generation/transmission/distribution systems.

Proponents of S. 406 assume that these operational problems, and resulting costs to utilities and their customers, can be minimized and controlled by contract. They assert that utilities can write -- and enforce -- contracts that place the independent generator under effective utility control on the necessary hour by hour basis. However, contracts are no substitute for integrated operation, especially where the interests of the utility and the generator may be inherently dissimilar and prone to conflict, and especially over the longer term.[20/]

[20/] Economists recognize that complex contracts -- even when they adequately protect the parties' expectancies -- are a
(Continued)

Reliance on contracts presents at least two major problems, both related to what economists call "transactions costs." These transactions costs are not just the up-front cost of consultants, lawyers or negotiators. Rather these costs reflect risks that agreements will not be kept, that performance will be substandard, or that other resources will have to be committed and spent to ensure expected performance. The greatest risk is that long-term contracts involving significant uncertainty and specific assets create an incentive for one party to take advantage of the other through "opportunistic" behavior in the future.[21/] Utilities have witnessed this behavior many times in

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second-best substitute for vertical integration of all utility services. Complex contracts inherently are costly to write and enforce. As the OTA has stated:

> "[C]ontracts may have some shortcomings when compared to arrangement within a single organization, as in a vertically integrated utility. For example, given the overall uncertainty in the power industry, anticipating all terms and contingencies requires extensive effort."

OTA, supra, at 15.

[21/] According to economists, opportunism arises directly because of the "lock in" effect of a long term contract. Even if there is extensive competition among EWGs prior to the signing of a contract, and even assuming that neither party enters the agreement with hidden intentions, once the contract is signed both parties will realize that the other is completely dependent. If new or unforeseen conditions or disputes arise, one party (knowing that litigation is extremely costly and the outcome is uncertain) may attempt to extract additional concessions from the other. Economists have noted that the supplier is the more likely opportunist in such a situation. Benjamin Klein, Robert G. Crawford and Armen A. Alchian, "Vertical Integration, Appropriable Rents, and the Competitive Contracting Process," 21 Journal of Law and Economics 297, 300 (1978).

the past two decades with fuel supply contracts. However, the cost to a utility of switching fuels on short notice in the face of such behavior is small compared to the cost of obtaining capacity from an alternative source, or maintaining excess capacity in anticipation of actual or threatened EWG supply interruptions.

The resulting problems are, first, that it may be extremely difficult and costly to monitor an EWG's performance of its obligations. To police compliance with dispatching instructions, for example, the utility would have to make an intrusive review of the EWG's operating records. Secondly, if non-performance is detected, legal action to enforce the contract is unlikely to be an adequate remedy for the utility. Litigation is costly, uncertain and lengthy. Monetary damages, or even specific performance of the contract, awarded after the fact would not enable the utility to meet its obligation to serve at the time of the non-compliance.[22/] The recent history of utilities' transactions with the natural gas industry is instructive. Gas suppliers have not hesitated to declare force majeure during economic adversities, dragging their customers into prolonged litigation of the precise meaning of their contracts.[23/]

[22/] As one commentator has noted, "financial penalties for failure to provide capacity will not keep the lights on." J. A. Casazza, "Free Market Electricity: Potential Impact on Pooling and Coordination," Public Utilities Fortnightly (Feb. 18, 1988) at 20.

[23/] The situation is analogous to the one that occurs when a bank's debtor is about to default on a huge loan. If the (Continued)

Take-or-pay contracts could alleviate the problem of dispatchabilty. Indeed, in order to obtain financing, EWGs may find that the investment community will insist that EWG facilities be "backed" by take-or-pay contracts. Under this approach, the EWG would receive the same payments regardless of whether it is producing power or not, and presumably, therefore, would be willing to submit to utility dispatch. However, take-or-pay contracts have the effect of converting the EWG to baseload capacity. Few utilities can afford the luxury of paying for EWG power but not taking it. The experience of Houston Lighting & Power Company well illustrates the effects of such contracts on efficient operation. HL&P currently must operate coal plants in a cycling mode because its system could not otherwise accommodate all the power that cogenerators are delivering during off-peak periods. These coal plants were designed to be super-critical baseload facilities. As a result of frequent adjustments of output, plant efficiencies are lost, operating costs are increased, and the plants suffer more wear and tear. In effect, take-or-pay contracts will lock the utility into buying power it would not want under a system of economic dispatch and can greatly distort the utility's operations.[24]

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bank cannot afford to write off the loan, the debtor is able to exact concessions notwithstanding elaborately drawn loan agreements that give the bank all the "rights" in the world. The larger the debt, the more leverage the debtor often has.

[24] As one member of the Utility Working Group aptly stated in its comments on FERC's IPP NOPR: "If that [i.e., long term take-or-pay contracts] is the only type of contract IPPs

(Continued)

(iv) Additional Costs of EWG Dependence on Natural Gas

Analysts assume that, in order to minimize development costs and expedite siting, non-utility generation facilities will be gas-fired turbines or combined cycle facilities.[25] It remains to be determined whether EWG developers voluntarily would incur the higher capital costs of establishing dual-fuel capability for these units, or the associated costs of inventorying alternate fuels. As a result, EWGs as a class could be highly vulnerable to escalating fuel costs as demand for natural gas increases.

Utilities have learned that they must retain maximum control over the fuel mix of the generation on which they rely. EWG power, with gas as the likely fuel of choice in most cases, could be a step backward. A serious reduction in the supply of natural gas or a sharp increase in gas prices could produce a wave of failures among non-utility generators. Abandonment of plants dependent on these fuels, even in the development stage, would necessitate a scramble by the utility to meet its planned-for capacity by other means. Abandonment of operational EWGs, as occurred with some gas-based industrial plants in the 1970s,

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have to offer, then all they are truly offering are efficiencies gained through freedom from regulation." Comments of Arizona Public Service Co., Docket No. RM-88-4-000, at 2-3.

[25] According to the Natural Gas Alliance for the Generation of Electricity (NGAGE), "natural gas fired systems are projected to comprise over half of NUG [non-utility generation] additions." NGAGE, "Natural Gas-Fired Power Generation and the Need to Amend the Public Utility Holding Company Act," (May 16, 1989) at 2.

could seriously jeopardize the reliability of the utility and its network, necessitating maintenance of other reserves at additional cost.

Again, contractual protections, e.g., financial assurance for performance, would offer highly imperfect protection for purchasing utilities. A utility might have little choice but to try to take over a failed project, in effect committing itself and its rate payers to a demonstrably uneconomic plant. Again, the result would be higher electricity costs and uncertain reliability.

Independent power producers could try to shift this risk (along with others) to the purchasing utility, i.e., by including in their long-term mandatory power purchase agreements a fuel cost escalator. Again, the ability of a utility to reject a proffer of EWG power because it does not want to agree to a fuel-cost-escalator provision may be severely constrained by state regulatory processes that take a shorter term view. The resulting obligation (as with a take-or-pay obligation) could adversely affect the utility's future costs, its balance sheet and its bond rating, thereby raising the cost of both debt and equity financing for the utility and its rate payers.26/ Again,

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26/ In recent remarks, a representative of Moody's Investor Service observed:

> "One cannot ignore the debt implication in, for example, the purchase power contract between a highly leveraged 'independent' and a utility company which maintains substantial equity in its capitalization. It is likely that the credit stature of the utility substantially

(Continued)

post experience indicates that state regulators would fail to recognize and quantify these costs to a purchasing utility, resulting in uneconomic decisions.

(vi) Additional Costs Due to Stranded Investment

Enactment of S. 406 will create intense pressure on regulated utilities to grant EWGs access to transmission facilities for the purpose of making sales to interconnected utilities. Whether FERC would resist these pressures appears problematic. The loss of these sales could cause significant increases in electricity costs to consumers over the longer term. According to the Transmission Task Force Report, 16 investor-owned utilities have firm power contract sales with unaffiliated wholesale customers accounting for over 15 percent of their total sales.27/ These and other utilities that make substantial sales of wholesale power could face intense competition from highly-leveraged EWGs with their artificial tax advantages. Loss of these loads would mean that the embedded costs of idled capacity would have to be recovered from the franchised utilities' remaining retail customers.

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supports, through the terms of the contract, the financing capability of the 'independent'. . . .[T]his variance is accounted for by imputing an added debt and interest component to the company's financial statements . . . ."

R.W. Burke, "Independent Power Producers and Their Impact on Utility Debt Quality,"at 5 (unpublished, delivered to Energy Daily's Annual Utility Conference, Washington, D.C., Nov. 2, 1989).

27/ Transmission Task Force Report, supra, at 37.

Furthermore, the creation of EWGs will create strong pressures from large retail customers of franchised utilities to purchase power from EWGs directly. Demands will be made on local utilities to transmit power for the EWG to such customers, with residential and other rate payers left to bear the costs of the resulting stranded investment.[28/] Industrial load loss can have profound impacts on customers' rates. For example, one of ERC's member companies makes a very substantial portion of its total power sales to a small number of industrial customers. It has been estimated that the loss of as few as three of those industrial customers would require as much as a 35 percent increase in all other rates in order to meet the utility's revenue requirements.

For all these reasons, utility reliance on a new class of EWGs is likely to result in higher, not lower, electricity rates. The Committee must make a careful analysis of the risks of this outcome before taking any action on S. 406.

3. Congress Should Make a Thorough Review of All Relevant Factors and Policy Options Before "Deregulating" The Generating Segment of the Electric Industry.

[28/] For purposes of defining a "wholesale" transaction, S. 406 does not distinguish between sales to utilities and sales to a power broker/marketer who takes title to the power with a view to resale. The result may be to facilitate the creation of EWGs whose sole purpose is to produce power for a large industrial customer, with sales made through an affiliated broker. If located in proximity to the customer, such service could even be accomplished without recourse to the local utility's transmission facilities.

A. Congress Should Resist Efforts Administratively To Amend the Federal Power Act.

ERC opposes enactment of piecemeal legislation with the possibility of far reaching adverse consequences. By enabling the formation of numerous EWGs, S. 406 effectively would clear the way for FERC to carry out what may well be a program of substantial deregulation of power generation in this country. Such deregulation, particularly as regards rates for wholesale sales, would derogate from the original legislative intent underlying the Federal Power Act.[29]

FERC's recent consideration of proposals that would eliminate the principle of cost-based regulation of wholesale rates is indicative of where the Commission appears to be heading. Under the March 1988 NOPRs, an independent producer's sales at rates established through bidding would be deemed "just and reasonable," without regard to the cost of providing that service or whether the price is the same as that charged to another purchasing utility.

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[29] Under the FPA, FERC has exclusive, nondelegable and nonwaivable jurisdiction over the rates, terms and conditions governing sales for resale and transmission of electric energy in interstate commerce. Sales by an independent producer at wholesale in interstate commerce would be clearly jurisdictional. FERC cannot lawfully exempt any such facility from the requirements of the Act. *Cf.* *FPC v. Texaco, Inc.*, 417 U.S. 380 (1974) (FPC could not exempt small natural gas producer from applicable requirements of Natural Gas Act). On the contrary, when Congress has intended to confer on FERC the authority to exempt sales of power from FPA regulation, it has done so explicitly, as in the establishment of a new class of "qualifying facilities" with special status under Sections 201 and 210 of PURPA.

FERC's proposed approach departs significantly from that established by Congress when it enacted the Federal Power Act over 50 years ago. While no single method is required to be followed in determining just and reasonable rates, courts (and state commissions) consistently have held that electric rates should be based upon the cost of service to the utility's customers, including a reasonable return on equity.[30/] Cost of service is inextricably tied to the seller's costs.[31/] In the Texaco case, the Supreme Court specifically rejected the argument that "market price" automatically can be equated with the just and reasonable standard.[32/] In light of Texaco, the apparent preference of at least some members of the Commission for market-based pricing of independent producers' sales is of questionable consistency with Congress' intent in enacting the Federal Power Act.

Moreover, the issue of mandatory access to utility transmission systems for EWG power certainly will arise before FERC (if not first addressed by Congress) if the current

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[30/] Alabama Electric Coop., Inc. v. FERC, 684 F.2d 20, 2[illegible] (D.C. Cir. 1982)

[31/] Farmers Union Central Exchange v. FERC, 734 F.2d 1486, 1502 (D.C. Cir. 1984) (in determining "just and reasonable" rate for oil pipeline transportation under ICC Act, "the most useful and reliable starting point . . . is an inquiry into costs"; FERC's proposal to set blanket ceiling rate "abdicated its statutory responsibilities").

[32/] Texaco, Inc. v. FPC, supra, 417 U.S. at 397 ("the prevailing price in the marketplace cannot be the final measure of 'just and reasonable' rates mandated by the Act").

legislation is adopted. According to the FERC Transmission Task Force:

> The pressure for transmission access in the future is likely to come not only from retail and wholesale customers, but also from independent suppliers. . . . Independent power producers . . . will create a need for transmission access policies that ensure owners of generating plants that transmission service will be available when needed.[33]

One of the chief proponents of S. 406 predicts:

> [A]s bidding systems are introduced in more and more states, and as demand for new capacity increases, pressure for enhanced access to transmission facilities will grow from both independents and utilities.[34]

Many observers believe that addressing the question of transmission access would be unavoidable following PUHCA "reform." There are strong indications that at least some Commissioners and FERC staff members are inclined toward some form of mandatory access and wheeling.

Even if FERC had legal authority to abandon cost-based rate regulation (which ERC disputes), and to mandate transmission access, whether the Commission should do so can properly be decided only in the context of fundamental policy decisions about what role EWGs should play in the nation's energy future, and on

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33/ Transmission Task Force Report, *supra*, at 67.

34/ Testimony of Paul J. Elston, President and Chief Executive Officer, Long Lake Energy Corporation to the Subcommittee on Energy and Power of the House Committee on Energy and Commerce (May 24, 1989) at 9. Mr. Elston recommends that there be created "a new Federal 'public interest' wheeling authority" for this purpose. *Id.* at 15.

what terms. It would be an abdication of Congress' responsibility to set basic national energy policy if it now decided only a threshold portion of this issue by encouraging the widespread development of non-regulated power producers and leaving to FERC the resolution of the other issues that inextricably are involved.

B. Congress Must Consider the Effects of Impending Environmental Protection Requirements on the Utility Industry.

The Committee is well aware of various legislative proposals which, if they become law, will impose upon America's electric utility industry additional costs in order further to protect the environment. No other sector of the economy faces so many different environmental legislative proposals that could affect so substantially the way it does business. Legislation like S. 406, which could change the structure of the industry, should be considered only in the context of these other proposals.

The impact of increased environmental protection requirements for utilities could mean substantial new costs for utilities and their consumers. For example, a study conducted by ICF Resources, Inc. for the Environmental Protection Agency estimates that Title V (acid rain) of the Administration's Clean Air Act reauthorization bill will result in additional annual costs to utilities of $3.5 to 4.1 billion (1988 dollars) in the year 2005. A study conducted by Temple, Barker and Sloane for the Edison Electric Institute estimates even higher costs to rate payers. That study projects $5.5 billion in additional costs every year between enactment and the year 2000, increasing to $7.1 billion per year from 2000 to 2010. The Department of Energy estimates the Administration's bill will increase the cost of producing electricity from coal by approximately 5 to 8 percent.

There also is the prospect of international agreements or domestic legislation that, in an effort to avert a perceived threat of global warming, could mandate changes that would impose astronomically high costs on the electric utility industry and its customers. Proposals have been discussed to "stabilize" carbon dioxide emissions at current levels by, say, the turn of the century. More drastic proposals would seek reductions from current levels by as much as 20 percent by the year 2000. The attempts to project the costs of such proposals have only just begun. However, the kinds of global warming regulations being proposed domestically and in international forums could require extraordinary increases in the cost of producing electricity, as well as reductions in both electricity supply and demand.

Congress should not now consider amendments to PUHCA that could affect the basic structure of the utility industry without giving full consideration to the impact of environmentally-related cost increases on utilities' ability to continue to serve the public. A number of key questions should be addressed. For example, will the industry be more or less able to adapt to the cost increases associated with environmental protection if EWGs proliferate? If the nation were to pursue drastic policies of energy conservation, how would that impact utilities trying to cope with competition from EWGs? Would utilities facing such competition lose incentives, or the ability, to foster conservation? To the extent that, to accommodate environmental requirements, there is fuel switching by existing utilities from coal to natural gas, will the resultant upward pressure on natural gas prices also result in EWGs incurring fuel cost increases that render them financially and operationally unreliable?35/ All of these issues need to be addressed before

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35/ More, of course, is at issue than mere cost. The Energy Information Administration in its January 1989 report, "Electricity Generation from Natural Gas: Prospects and Implications for the United States," observed:

> "[G]as supplies from economically recoverable resources could be counted on to meet the projected range of gas consumption for electricity production through the economic lives of plants in operation by 2000, but this was true only under certain conditions. First, it assumed . . . no additional construction of gas-fired plants after the year 2000.
>
> . . . .
>
> "If utilities should choose to consume gas at the same or higher levels than those projected in 2000, it appears that the assumed volume of economically recoverable resources would not be adequate to meet requirements at competitive prices."

Will America, as a consequence of aggregate increase in natural gas demand, become a larger importer of natural gas? If so, is that in the national interest? And, even if domestic gas supplies are adequate to meet combined requirements of utilities and EWGs for the foreseeable future, will the United States have the gas transmission infrastructure necessary to take care of those needs?

undertaking piecemeal legislation that could affect the future structure of the electric utility industry, as well as its choice of fuels.

C. Congress Must Consider Other Policy Options to Stimulate Construction of Needed Generating Capacity.

Proponents of S. 406 argue that non-regulated independent power facilities will be necessary to meet anticipated increases in the nation's demand for electric power in the 1990s. Underlying this argument is the assumption that franchised utilities in some localities will be unable or unwilling to build the needed capacity themselves. This premise is not correct or, where locally apparent, is the result of state actions and conditions.

Even if there were validity to such a premise, which the ERC strongly disputes, the logical inquiry is whether there are better policy options whereby the nation can secure the needed construction without incurring all of the uncertainties and costs associated with the EWG option. Several such alternatives clearly are available at the state and federal levels.

One option is legislation that would enable regulated utilities to recover the costs of construction work in progress (CWIP). Historically, the "used and useful" principle of utility ratemaking has been applied so as to deny a utility any current return on plants under construction but not in service. The overall CWIP burden on the industry is very significant. As of

December 31, 1987, CWIP equalled approximately 15 percent of IOUs' total net electric plant.[36]

The traditional treatment of CWIP for ratemaking purposes is a major disincentive for utilities to invest large amounts of money in capital-intensive generating facilities that take a long time to build and bring on line. CWIP reform would provide an immediate and effective incentive for new construction. The final cost of needed capacity would be substantially reduced by allowing CWIP in rate base and the utilities' financial positions would be strengthened.

As another example, Congress should consider revising the way the nation deals with nuclear power. One important element of this alternative would be a major effort to develop nuclear technologies that can better meet public concerns about nuclear power. The other element of the option is a concomitant streamlining of the process for siting and licensing such facilities. Given a national commitment to pursue this option, such facilities could substantially alleviate longer-term concerns about the country's generating capacity and fuel supplies.

All of these options should be considered pursuant to a comprehensive policy for the future of the American electric power industry. Above all, Congress should refrain from piecemeal legislation ostensibly aimed at increasing electricity supplies without full and fair consideration of alternatives. There are well tested and proven approaches to meeting the need for future generating capacity that would assist franchised utilities to continue to meet their obligation to serve. These alternatives to non-regulated facilities must be considered at both state and federal levels.

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[36] Arthur Andersen/CERA, supra, at 84-85. While CWIP totalled 25 percent of net IOU plant in 1977, the subsequent drop in CWIP to present levels can hardly be called an improvement in the industry's fundamental health, inasmuch as it largely reflects a slowdown in the industry's construction of new facilities resulting from downward revisions to the demand growth projected in the early-to-mid 1970s.

CONCLUSION

The regulated electric utilities represented by ERC respectfully oppose enactment of S. 406. We certainly dispute the view that the electric power industry in this country is "broke" or in danger of becoming so. The facts are quite to the contrary. We are certain that S. 406 would not be the right "fix," even assuming a "federal fix" were needed. PUHCA "reform" simply would be an initial step in an unpredictable process which could establish on a widespread basis a new class of non-regulated electric suppliers. These EWGs might enjoy artificial cost-of-capital advantages enabling them to appear to price power below the apparent cost of utility generation; but the total cost of providing full electric service -- adequate and reliable delivery of power when and where the consumer needs it -- is likely to be more costly with EWGs.

The challenges of the past decade have pressed the capabilities of the franchised, regulated utility industry, but overall that industry has performed exceedingly well. As stated by the Office of Technology Assessment, "There is no crisis warranting immediate action by policymakers."[37] Congress should not now enact "piecemeal" legislation which would tend to replace electric service from facilities now regulated in the public interest with those which do not have this obligation of public service.

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[37] OTA, *supra*, at 27.

PREPARED COMMENTS OF
HOUSTON LIGHTING & POWER COMPANY
FILED WITH THE SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES
REGARDING PRINTED AMENDMENT 267 TO SENATE BILL 406

FEBRUARY 1990

Houston Lighting & Power Company respectfully submits these comments in opposition to P.A. 267, The Competitive Wholesale Electric Generation Act of 1989. We believe that it is both unnecessary and ill-advised to amend the Public Utility Holding Company Act (PUHCA) to promote the development of independent power producers (IPPs). Our opposition to this initiative is based on our conviction that facilitating the development of IPPs exposes consumers to potential abuses and undermines the integrity of the nation's electric supply system.

While some utilities regard the prospect of abdicating their responsibilities for the generation function as an attractive option, we believe that such an approach would increase consumer costs and create serious reliability problems. Many utilities which favor the development of IPPs do so generally because they have lost confidence in the regulatory compact and are unwilling to risk investment in new generating capacity. However, the problems associated with faulty regulatory decisions such as unwarranted disallowances will not be solved by encouraging the development of unregulated power producers. Nor will amendments to the PUHCA resolve the inequities of retrospective regulatory reviews. In fact, utilities may be subject to increased regulatory uncertainty as their dependence on non-utility generation increases.

Encouraging an increased dependence on unregulated sources of power will, in our view, have long-term adverse effects on electric consumers and on the nation's supply of electricity. Such changes will jeopardize the reliability and ultimately increase the costs of electric service to American consumers without providing any tangible benefit. In addition, the current growth of independent suppliers (for better or for worse) in the absence of statutory or regulatory changes indicates that the proposed amendments to PUHCA are not needed. Furthermore, we believe that the Act continues to offer consumer protections that are not otherwise provided.

It is for these reasons that Houston Lighting & Power Company opposes this amendment to S. 406. We believe that the federal and state governments should undertake a comprehensive analysis of electric power options and policies before amending the PUHCA. In our view, it is premature for Congress to consider such a far-reaching initiative that has such an enormous influence on the nation's economic and social well-being.

SPECIFIC AREAS OF CONSIDERATION

1.

Changes to the PUHCA will weaken the reliability of the nation's electric power supply. The proposed amendment will impede planning for future demand and erode the utilities' obligation to serve. It overlooks operation and control issues, and fails to consider fuel diversification and supply concerns.

Planning/Coordination

No utility is an island, because each is integrated into a complex network in which complete and open exchange of data and information occurs between regional utilities to insure that an adequate power supply is always available. At present, a single utility or, in the case of power pools, a group of cooperating utilities, is responsible for planning and operations in a certain geographic region. Functions now routine to utilities would become increasingly complicated if the PUHCA were amended as proposed.

There are many considerations that utilities must examine during the planning stages of new generating facilities to assure that the facilities will be able to operate reliably in the bulk power system. Generating plant characteristics such as dispatchability, size, fuel diversity, location, and availability are factors which must be taken into consideration for effective long-range planning. Utilities currently exchange information including load projections, design and operational specifications, load flow studies, cost analyses, and stability studies. Utility involvement in power pools, reliability councils, and statewide planning efforts sanctioned by state regulators ensure that the appropriate data is available for long-range planning.

Since IPPs are by definition unregulated, coordination would not be subject to state oversight, but instead would be voluntary, if and to the extent the IPP chooses to cooperate. Moreover, once an IPP is constructed, there are no regulatory procedures for monitoring operational characteristics (e.g. forced outage rates, maintenance rates, unit rating, and energy output) that are essential to maintaining reliability.

Obligation to Serve

Utilities serve their customers under the auspices of federal, state, and/or local regulating bodies and are charged with an obligation to serve all those within the utility's service territory. IPPs are not required to fulfill this same obligation to serve. As is the case for any private business, the risk exists that non-utility generators may be short-term enterprises that are viable only as a result of available, low cost fuel, tax breaks, and favorable financing options. Changes in those factors which currently make IPPs an attractive investment may vanish in the future.

Because there is no statutory obligation to serve imposed upon IPPs, economics and contracts are the only assurances that IPP capacity will be there to meet future electric power demands. However, no contract can guarantee performance, nor can it guarantee engineering reliability, eliminate planning, construction and operational conflicts, or impose the obligation to serve.

Operation and Control

Contrary to the claims of IPPs, an IPP cannot just build a generating facility and hook-up to a utility's electric system without seriously jeopardizing electric service. Technical concerns such as thermal and mechanical stress throughout the system, load following capability, and reactive power are considerations in providing reliable electric power that may have been overlooked as IPPs rush to get into the electric generation industry.

The reliability of an integrated generation/transmission/distribution system, or interconnected power pool, is dependent upon the reliability of each individual component of that system, as well as upon the ability of the controlling entity to coordinate the planning, construction, and operation of a single unit. Each entity is dependent upon every other entity. That raises a number of reliability concerns regarding the incorporation of large amounts of unregulated IPP power into utility supply strategies.

Fuel Diversity and Availability

When planning generation capacity, utilities attempt to diversify fuel types and sources to ensure that long-range fuel needs are satisfied. The availability and recent low prices of natural gas, combined with short construction time frames and relatively low capital costs for gas-fueled generation units, have made combustion turbines the predominant choice for IPP facilities. A sudden change in the fuel supply environment (i.e., the 1973 Oil Embargo) or government regulations (i.e., past Fuel Use Act restriction on natural gas use), even seasonal fuel curtailments, could drastically limit the ability of many IPPs to obtain fuel. Such a situation can only serve to reduce electric system reliability.

2.

The IPP industry is growing rapidly: there is no need to loosen PUHCA restrictions on the industry.

Efforts to amend the PUHCA to facilitate the development of IPPs are unnecessary and ill-advised. The IPP industry is growing rapidly. An analysis of the independent power industry by RCG/Hagler, Bailly, a Washington D.C. consulting firm, identified 2,321 IPP projects in operation, representing a total capacity of 26,320 megawatts with annual revenues of $6 billion. The firm also found that investment in IPPs will grow to as much as $42 billion between 1989 and 1995. The National Association of Energy Service Companies reports that financing for IPPs topped $3.275 billion in the first quarter of 1989.

Utility activity in the IPP industry has also grown steadily. In 1988 alone, utility involvement in IPP projects more than doubled from 4,400 megawatts to over 11,000 megawatts. The need for amendments to the PUHCA has yet to be adequately demonstrated. In short, sufficient evidence has not been presented to substantiate the claims of those who insist that the PUHCA restricts the development of IPPs.

3.

The regulatory constraints applicable to IPPs under PUHCA are still necessary to protect consumers.

PUHCA was originally passed in 1935 to protect consumers from a number of abuses occurring in the utility industry. Since that time, a variety of state and federal laws and regulations have been put into place regulating public utilities. Even in the absence of PUHCA, the remaining regulatory structure within which utilities function would continue to protect consumers and investors from potential abuses by utilities subject to regulation.

IPPs, however, are not subject to traditional utility regulation. If they were also exempted from the PUHCA, consumers would have little or no protection from the abuses the Act was designed to prevent. In fact, a number of those abuses, such as highly leveraged capitalization, inaccurate and misleading financial and accounting practices, and geographic dispersion between management and operating companies, are likely to be characteristic of the unregulated independent producers industry.

4.

Exempt Wholesale Generators (EWGs) will not result in lower electricity costs.

IPPs claim that because they can take advantage of highly leveraged project financing, they can generate power more cheaply than utilities. However, this financing is available to IPPs primarily because of contractual commitments by utilities which typically provide IPPs with an assured market and a known price for their facilities' output. Market risk is therefore transferred from the IPP to the purchasing utility, which translates into a higher cost of capital and increased costs for ratepayers.

Investments in electric generating units entail significant market risks due to the long lives and capital intensiveness of such projects, coupled with the tremendous uncertainty in long-term forecasts. Under contracts which provide an assured market and assured price to IPPs, the purchasing utilities bear the risk that economic, social, or technological changes might make IPP power uneconomical in the long run. The risks assumed by utilities purchasing power from IPPs are taken with no underlying equity investment, resulting in an increase in the utility's overall weighted average cost of capital.

5.

Separating a system's mutually dependent areas of decision-making will introduce different kinds of inefficiencies that will be more costly than those intended to be addressed by competition.

One item that distinguishes the electric utility industry from other businesses is the absolute necessity of coordination among its components. Utilities forecast the need for power, the most economical choice to produce and deliver it, and how to ensure its reliability. This integrated approach enables utilities to optimize the entire system. Not only are individual utilities vertically integrated, but close coordination among utilities enables them to share generation and transmission to minimize costs and improve reliability. Even if competitive generators could operate at a lower initial cost than utilities, an issue that is certainly debatable, long-term system economics also depend on how well the components work together.

Moreover, under the present industry structure utilities often jointly support research and development and collaborate in demonstrating new technologies. Competing companies would have less incentive to cooperate, which could jeopardize opportunities for joint R&D. Since such R&D is costly and often requires joint efforts, it is highly unlikely that IPPs, which exist only because of their alleged ability to provide power at a lower cost, will assume the costs of such endeavors.

6.

The proposed amendment appears to be based on the untested premise that competition is better than regulation.

Houston Lighting & Power disputes the notion that the current regulatory process will fail to ensure reliable and affordable power to consumers in the future. Those who advocate abandoning the tried and true regulatory structure have yet to prove that changes are either needed or justifiable.

The electric utility industry has an enviable record of service and efficiency. The industry has provided reliable service for over a century and continually strived, through the development of new technologies, innovative load management, and coordination among vertically integrated utilities, to increase the economic efficiency and reliability of the nation's electric power supply. A number of recent government reports have praised the industry for its efforts to increase economic efficiencies in the generation and transmission of power through coordination and planning. For example, the FERC's Transmission Task Force Report to the Commission observed that:

> "The industry has made great strides in the past three decades in developing robust transmission grids and coordinating their planning and operations to save American consumers tens of billions of dollars a year."

In summary, efforts to amend PUHCA are not in the public interest. They are specifically aimed at promoting the development of independent power production with no indication that consumers or the nation will benefit from such development. The changes are not only ill advised, they are also unnecessary, based on the significant development of unregulated generation that has already occurred. Exempting these power producers from provisions of the PUHCA would place the American consumers at great risk. Houston Lighting & Power Company therefore urges this committee to reject the proposed amendment to S. 406.

National Independent Energy Producers

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WRITTEN STATEMENT OF THE NATIONAL INDEPENDENT ENERGY PRODUCERS SUBMITTED FOR THE RECORD

before the

UNITED STATES SENATE
COMMITTEE ON ENERGY AND NATURAL RESOURCES

Washington, DC

HEARINGS ON S.406, THE COMPETITIVE WHOLESALE GENERATION ACT OF 1989

February 1, 1990

I. INTRODUCTION

The National Independent Energy Producers (NIEP) is pleased to submit the following statement for the record on the "Competitive Wholesale Generation Act of 1989."

The National Independent Energy Producers (NIEP) is an association of companies that generate electricity for sale to utilities and develop cogeneration projects for a variety of users. NIEP membership is comprised of both publicly traded and privately held corporations which represent the entire spectrum of fossil fuel-fired and renewable technologies, including hydro, biomass, geothermal, wind, wood and waste-to-energy plants, as well as oil, gas and coal-fired cogeneration and wholesale generation facilities. We do not build ratebased powerplants.

NIEP is committed to increasing competition in electric power generation markets. Independent energy has grown out of the entrepreneurial and competitive climate fostered by the Public Utility Regulatory Policies Act of 1978 (PURPA). Since this 1978 legislation made the competitive power industry a possibility, independent electric producers have built more than 27,000 megawatts of capacity -- equivalent to 27 large nuclear power plants. In addition, this new industry has supplied about 20 percent of all new electric capacity since 1978.

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Independent generators in competitive markets are emerging as a vital suppliers to meet the demand for new electric generating capacity in the 1990s and beyond. NIEP believes that workable competition in the electric generation market will help meet the nation's need for reliable, low-cost electricity and further our nation's economic and environmental goals.

NIEP advocates amendment to the Public Utility Holding Company Act of 1935 (PUHCA) to remove institutional and regulatory barriers to market entry by independent generators of electricity (called "exempt wholesale generators -- EWGs" in the legislation). Currently, PUHCA blocks entry by independent generators which by definition lack market power, when it was intended to do something else -- end the monopolistic abuses associated with dispersed utility holding companies in the 1920s and '30s. Changes in PUHCA are essential to promote competition in the wholesale electric generation market for the benefit of the nation's consumers and to give utilities additional supply options in the coming round of powerplant construction.

However, without the means to protect the newly established competitive bulk power markets from anti-competitive behavior by entities possessing significant market power, the goal of increased competition could quickly be subverted. Therefore, to enhance competition in power generation markets and maintain vital consumer protections, we urge the Senate to include additional protections against the abuse of market power in S. 406.

II. WHY PUHCA REFORM IS NECESSARY

A. Competition in Power Markets

Capacity Needs

The need to amend the Public Utility Holding Company Act derives from the growing requirement for new electric generating capacity to maintain economic growth and our quality of life. The reliability of this nation's electric system (the ability to meet electricity demand instantaneously) has been a cornerstone of the development and regulation of the electric utility industry since its beginning.

That reliability is now threatened. The Department of Energy predicts that the nation will require 110 gigawatts of new capacity by the year 2000 in addition to what is currently planned by utilities. Substantial new electric capacity will be needed even sooner -- in the next five years -- to maintain economic growth and the reliability of our electricity supply.

In 1988's hot summer, a number of eastern and midwestern utilities hit peak demands they did not expect to reach until the mid-1990s, resulting in brown-outs, voltage drops and service curtailments for some customers. During the record cold of December, utilities across the nation hit new all-time and winter peak demand records. In addition, the December cold snap in the Southeast forced utilities in Texas and Florida to institute rolling blackouts because they did not have sufficient capacity to meet the peak demand.

Even without another hot summer or deep freeze, the nation's generating capability as a whole may drop below what is considered to be acceptable capacity margins as early as 1991.[1] In some regions of the country, namely the Northeast, the need is particularly acute. In addition, the North American Electric Reliability Council, the industry watchdog on reliability, notes in its latest assessment that, "planned capacity resources are projected to be insufficient in the United States by 1998 unless additional capacity commitments are made."[2]

This major threat to the reliability of the electricity system due to the need for new capacity resulted primarily from four developments of the last decade.

- First, the nation experienced an unusually long period of sustained economic growth leading to load growth exceeding utilities' projections. In addition, large investments were made in inexpensive conservation, dampening load growth. Additional cheap conservation and efficiency gains are probably not available and their absence may lead to a higher rate of growth in the 1990s. After years of sluggish growth in demand in the early 1980s, the Department of Energy predicts that the demand for electricity will grow, on average, 3 percent per year through the year 2000.
- Second, these utilities have been reluctant to build new capacity to meet that growth because of: a) regulatory disallowances of construction costs and capacity, b) the financial markets' shaken confidence resulting from the nuclear-cost-overruns, and c) prudence reviews that "second guess" utility capital spending programs.
- Third, utilities have cancelled or abandoned approximately 108,500 MW of proposed new capacity since 1980.
- Fourth, with so little new generation being added, the average age of the nation's inventory of powerplants has been increasing and many plants are approaching the end of their useful lives.
- Fifth, amendments to the Clean Air Act currently being considered may speed the retirement of old plants and require more investment in new plants.

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[1] The industry standard capacity margin is 17 percent reserve capacity. This equals the probability of one day power loss in ten years.

[2] North American Electric Reliability Council, **1989 Reliability Assessment: The Future of the Bulk Electric System Reliability in North America, 1989 - 1998**, September 1989, page 14.

The Growth of Competition in Power Markets

Thus, the threshold question for decision-makers is how the nation's demand for new electric generation will be met. NIEP believes that the experience of the last decade has shown it to be in the nation's interest to allow capacity needs to be met through competition in power markets. A recent report by the staff of the Federal Energy Regulatory Commission (FERC) concluded that,

> "The generation sector no longer exhibits the attributes of a natural monopoly, whereby efficiency would require a single seller; therefore competition can be used to discipline the investment and pricing decisions of the industry."[3]

The nation's consumers have much to gain from increased participation of independent generators in competitive electric power markets. First, a decade of experience with the Qualifying Facilities (QF) program under the PURPA has shown that non-utility generation could compete effectively on a cost basis with traditional utility facilities to provide efficient and reliable generation for the nation.

The success of the QF program in contributing new electric generating capacity and in bringing competition to power markets has far exceeded anyone's expectations. During the past decade, PURPA Qualifying Facilities (QFs) have supplied over 27,000 megawatts (MW) of electric generating capacity, or 3.5 percent of the nation's capacity. In a number of regions, non-utility generation has become critical in meeting loads.

Also, competitive bidding to supply future capacity needs is taking hold throughout the nation. Since 1984, utilities and/or public utility commissions in 27 states have adopted or are developing competitive bidding to procure generation capacity. In the same period, 40 requests for proposals have been issued, and almost 5700 megawatts of power sales contracts, representing 142 projects, have been awarded through bidding. In the relatively short time since competitive bidding began, over 500 megawatts procured through bidding have completed development and have begun delivering power.

Gains from Competition

NIEP believes that the nation's consumers have much to gain from increased competition in power markets. Wholesale generators in competitive markets are emerging as a vital supply option to meet the need for new electric generating capacity in the 90's. Among the major benefits to electricity consumers and our national economy from competition are:

- Assurance that an adequate and timely supply of electricity will be available by bringing new providers into the market;

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[3] Federal Energy Regulatory Commission, **The Transmission Task Force's Report to the Commission, Electricity Transmission: Reality, Theory and Policy Alternatives**, Washington, DC, October 1989, p.165.

- Continued shifting of construction and operating risks from ratepayers to wholesale generators in a manner that promotes efficiency and penalizes incompetence;

- Increasing the incentives for technological innovation and market responsiveness; and

- Encouraging least-cost pricing for consumers through increased supply options for consumers which will reduce cost and increase our national competitiveness. Reliance on market forces, not regulation, to determine prices will optimize the efficiency of the system.

Under PURPA, there have been demonstrable benefits from competition provided by QFs. As the number of QFs in the wholesale generation market has increased, competition also increases among those QFs, forcing them to develop better technology, creative contractual and financing arrangements in an effort to provide a stronger, more efficient and less costly facility.

Competition has stimulated technological development and innovation. There have been several energy generation and environmental control advances produced by QFs since the passage of PURPA, and, as research continues in this area, there is little doubt that more developments will arise in the future. Developments under PURPA include:

- Clean coal technologies such as circulating fluidized bed combustion to burn low grade waste fuels, award winning coal gasification designs, dry limestone injection process for reducing the SO_2 emissions from burning high-sulfur coal; and

- advancements in waste-to-energy technologies to burn wastes, such as municipal solid waste, tires, rice-hulls, and wood wastes, to produce electricity.

- The technology of hydro pumped storage is not new, but innovative uses of this technology can be found in the independent power projects.

- Independent facilities have led the way in developing commercial applications of geothermal, solar and wind power technology.

Unlike utilities, QFs cannot pass through costs onto the ratepayers. Thus, developers have found innovative ways to reduce their fuel cost risk by tying fuel prices to power purchase prices or securing long-term supplies at fixed prices. Facilities developed under PURPA have also demonstrated increased performance efficiencies including combined cycle systems, which add a steam turbine for generating additional electricity. Finally, independent facilities have achieved cost reductions relative to utility standards through lower construction costs and innovative construction contracting and performance guarantees.

There is no question that competition has led to lower costs for electricity. By the end of 1989, as a result of competitive bid solicitations, utilities signed contracts for nearly 5700 megawatts of capacity. In each of these cases, the utility decision to buy capacity rather than build themselves resulted from their own evaluation that wholesale power purchases would be cheaper.

Reliability of Independent Generators

Some utilities have disputed the gains from competition in power markets. They claim that without the utility obligation to serve, the proliferation of independent generation threatens the reliability of the nation's electric system. In the last decade, non-utility generators have proven their ability to both construct and operate power plants reliably. A recent study by the Congressional Office of Technology Assessment found no evidence that non-utility generators were any less reliable than traditional plants.

The National Independent Energy Producers have recently surveyed all public service commissions in states in which competitive bidding for new capacity has taken place. Data from the survey shows that only a tiny fraction of projects awarded contracts have been cancelled or have experienced significant delays. Of the 5700 MW awarded to date through competitive bidding, only 441.5 MW, has failed or been cancelled. As more bids are awarded, the failure rate of wholesale generators is likely to grow, probably approaching 20 percent and can be accounted for in the utility resource plan. However, even this number is far lower than recent utility experience. Over the past 10 years, non-utility generators have been relatively more successful than utilities in bringing projects on-line. During the same period, non-utility generation has grown to provide well over 27,000 MW of capacity, or 3.5% of our nation's supply mix.

Non-utility generators also have good records in operating their facilities reliably. Recent testimony by Southern California Edison and Virginia Power before their public service commissions reported that non-utility generation in their states met or exceeded traditional utility standards. In the recent California earthquake, cogenerators and other independent power producers stayed on line and helped PG&E to quickly restore service to consumers in the Bay Area. During the December deep freeze in Texas, cogenerators in the Houston area provided the utility with power **in excess** of firm contract commitments.

Selling power at a fixed contract price to wholesale markets creates strong incentives for reliable operation. Wholesale generators who are paid only for power actually delivered have a strong financial interest in the reliability of their facilities, stronger in many cases than utilities who can pass the costs of their mistakes onto ratepayers .

The nature of the project finance process provides a powerful discipline to insure reliability. For example, each project generally goes through four independent engineering evaluations: the developer, the construction-lender, the equity participant, and the suppliers of long-term debt. All have experts who intensively review every aspect of the design and construction plan of the project. This review is far more comprehensive and intensive than that given to a utility project in an after-the-fact prudency review by a public utility commission.

Nevertheless, some utilities argue that you cannot count on independent energy projects because independents unlike vertically integrated utilities (which control generation, transmission and distribution) do not have an "obligation to serve". However, experience in other industries indicates that vertical integration is not required to maintain reliability. As William McCormick, Chairman and CEO of CMS Energy/Consumers Power Company, recently noted, "Natural gas and telephone service are just as important to consumers as electricity. Yet those industries are largely disintegrated. Nevertheless, their distribution sectors maintain high reliability and a strong service obligation to consumers through reasonable and enforceable contractual relationships." [5]

Although independents may not have a statutory obligation to serve, they clearly have the incentive and a contractual obligation to serve, both in their power sales agreement with the utility and in multiple agreements with lenders. Independents are subject to obligations to deliver power according to specific operating standards. They suffer severe financial penalties if they fail to satisfy these commitments. They also rely on the same performance guarantees from equipment suppliers, such as General Electric and Westinghouse, that utilities rely on in building their plants. In the rare event that an independent project fails, performance obligations flow to the mortgagor whose only recourse to recover his investment is to operate the facility and deliver power in accordance with the power sales agreement.

For these reasons, it should be no surprise that the record shows that the market-based incentives of contract generation have insured that independents are developing least-cost reliable power on schedule. Independents have also contributed to reliability by pioneering efficient combined-cycled cogeneration plants with fuel-switching capability and by building smaller plants which can be located closer to load centers, reducing the risk of major supply interruption when a large nuclear or coal-fired central station goes down.

Financing of Independent Power

In addition, some utilities have made the argument that independent generators do not bring any efficiencies to the market, they just enjoy an artificially low cost of capital because they are highly leveraged. The argument goes: utilities are traditionally financed by 50 percent debt and 50 percent equity. Independents, on the other hand, are generally financed by 80 percent debt and 20 percent equity. Theory tells us that debt is more secure than equity and demands a lower return than equity. Most importantly, interest on debt is tax-deductible, reducing the overall cost of capital. So, say these utilities, the independent power industry exists by a quirk in the tax code.

However, this argument oversimplifies the complexities of financial markets and regulation. A recent analysis by the staff of the Senate Committee on Energy and Natural Resources concluded that this concern was "not well-founded". The amount of leveraging by utilities is administratively determined by regulators, not by the market. These regulators, who may have other public policy goals besides optimizing the cost of capital, may insist on a ratio between debt and equity that may be lower than financial markets could bear. Utilities are not anxious to change that ratio, since their shareholders earn a regulatorily determined return of equity.

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[5] Testimony of William McCormick, Chairman and CEO of CMS Energy/Consumers Power Company, before the Committee on Energy and Natural Resources, United States Senate, November 9, 1989, page 6.

On the other hand, independents rely on the market to determine the optimal amount of leveraging, the cost of debt and the return on equity. It is the choice of the market to strike the most efficient and appropriate balance between risk and leverage to minimize the cost of capital. Capital markets allocate the inherent risk of a project among debt and equity to optimize the cost of capital. To maximize efficiency and achieve the lowest cost of capital, the proper level of leveraging for a powerplant should be determined by the market.

Financial markets recognize that projects have the same value and risk no matter who owns them. The plants are long-lived tangible assets, which upon completion, will produce electricity is they are run well. Even if power sales were to cease, EWG assets can have enormous salvage value. We believe that over time, as artificial barriers are removed, the debt-equity ratio and the cost of capital for incremental projects, utility or independent, will converge.

Some utilities carry the financial unreliability argument further to say that the cost of capital for EWGs is also lower because the risk is shifted to the purchasing utility. Thus, the utility cost of capital rises as it buys more power from independents. This argument is unfounded, based upon a false notion of what PURPA actually requires, and assumes that utility executives will voluntarily make decisions which are bad for ratepayers and shareholders. Since all purchases from EWGs will be voluntary and the terms and condition of the contracts will be determined by the utility with other competing options, it is more likely that utility executives will make good decisions and will only enter into contracts which benefit their ratepayers and shareholders. In fact, power purchase contracts for QFs and other wholesale generators are typically "take if tendered" for peaking or stand-by capacity and "take and pay" for energy when it is delivered. Quite clearly, the risk is shifted to the developer, who does not get paid if the plant does not perform.

Furthermore, utilities regularly purchase power on a short or long term basis from other utilities with no adverse affect on their cost of capital. Since PURPA, there is no evidence that Wall Street has assessed any financial penalties for utilities with QFs in their service territories. In addition, under the proposed amendments to PUHCA, utilities are under no obligation to purchase power from independents. Utilities control the terms and conditions of the power sales contract into which they enter. If utilities sign good contracts, they will obtain the required products and services from independents and will shift cost risk away from their ratepayers.

Finally, buying power from independent generators and QFs displaces the need for utilities to undertake capital intensive construction programs. William Berry, CEO of Dominion Resources, testifying to the Senate Committee on Energy and Natural Resources on November 16, 1989, noted that if he had to build the 2,000 MW of capacity provided by independents through competitive bidding, he would have had to raise $3 - 4 billion to finance the construction. Mr. Berry expressed concern that need for that much capital would have harmed Dominion's credit rating. Notwithstanding the purchase of 2,000 MW of capacity through competitive bidding, Dominion's credit ratings was in Mr. Berry's words, "A+."

With the proposed amendments to PUHCA, utilities will never be forced to purchase power from EWGs. Amendment of PUHCA will create another viable supply option from which utilities can choose and competition produces demonstrable benefits for ratepayers.

B. Barriers to Entry: PUHCA and Competition

Competition in generation markets cannot fully develop amid the complex regulatory schemes that control investment decisions and operation. The benefits of competition can only be fully realized by the removal of institutional barriers, principally those under the Public Utility Holding Company Act. PUHCA, as currently structured, impedes the development of independent generation facilities and competitive power markets by effectively barring market entry by new suppliers.

Passed in 1935, the Act was intended to protect investors and consumers from the abuse of market power by utility holding companies so prevalent at the time. The protections against the abuse of market power embodied in PUHCA are still relevant today. However, the drafters of the Act could not have anticipated the changes that have occurred in the electric utility industry in the 55 years since enactment.

The detailed, harsh financial and corporate regulation under PUHCA to control market power abuses are inappropriate for independent power producers who lack market power. Most independent power facilities are organized as separate corporate entities because today's financial markets require them to be project financed. They therefore must be developed in a holding company structure which subjects them to regulation under PUHCA.

The "penalties" for becoming subject to regulation under PUHCA include:

- heavy regulatory, administrative and filing burdens imposed on holding companies, including financial reporting requirements, SEC supervision of acquisitions, contractual transactions with affiliates and the issue and sale of securities;

- absolute bars on certain activities, and the threat of forced divestiture, including restrictions on ownership of other business to those that are "functionally related" to the utility business; and

- loss of QF status for existing projects by becoming an "electric utility."

Clearly, development under PUHCA regulation is impractical for most independent generators. Therefore, independent generators are forced to follow limited PUHCA exemption strategies which, at best, may force them to make uneconomic or inefficient siting, technology, and sizing decisions for their facilities. At worst, the lack of exemption strategies discourages otherwise low-cost, reliable developers from entering and competing in the generation business.

PUHCA allows independents to become exempt by operating only in one state. However, that developer could still become subject to PUHCA's "two-bite" rule which effectively limits ownership of two or more facilities to less than ten percent, even in the same state.

An independent generator may avoid PUHCA regulation by meeting PURPA's size, technology or steam load requirements and seeking qualifying facility status under PURPA.[3] While PURPA continues to be successful in demonstrating the efficiency and reliability of non-utility generation, independent generators are ready to move beyond PURPA's technology and size limitations. In the future, QFs may not be able to fully satisfy the demand for new capacity in wholesale power markets in the 1990's, because of a limited number of steam hosts and other regulatory requirements.

Modification of PUHCA, therefore, is needed to assure that wholesale generation facilities, in addition to QFs and traditional ratebased plants, will be able to compete to meet the demand for electric generating capacity. In addition, changes which exempt independent generators which lack market power from PUHCA will allow developers to make truly economic and optimal choices in corporate structure, siting, size and technology.

II. PUHCA REFORM MUST NOT ALLOW ABUSE OF MARKET POWER TO THWART COMPETITION IN BULK POWER MARKETS

NIEP is supportive of both the intent and content of S.406, the "Competitive Wholesale Electric Generation Act of 1989," which would exempt a class of electric power generators from PUHCA -- as far as it goes. At the same time, NIEP notes with concern that the legislation is silent with respect to the market power issues raised by utility ownership of exempt wholesale generators (EWGs -- as defined in the legislation). PUHCA was intended to protect investors and consumers from the unbridled abuse of market power in the electric utility industry so common prior to its enactment. Legislation to afford exemptions to the Act should not dilute that goal.

Furthermore, without the means to protect the newly established competitive bulk power markets from anti-competitive behavior by entities possessing significant market power, the goal of increased competition could quickly be subverted.

Market Power

Market power is the ability of a single or group of buyer(s) or seller(s) to influence through anti-competitive activity the price of a product or service in which it is trading. Clearly, electric utilities, because of their franchise monopoly or single buyer status, have the ability to influence the behavior of generation markets. Furthermore, it seems clear that utility-affiliated wholesale generators (UWGs), which the legislation would exempt from PUHCA, would be able to gain a competitive advantage from the exercise of their parent's market power.

Potential anti-competitive activities which could arise from the exercise of market power in generation markets include:

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[3] The Federal Energy Regulatory Commission has completely exempted QFs from PUHCA under its rules.

1) **Self-dealing**: Self-dealing harms consumers when a utility pays an above market price for power to a wholesale generation affiliate or gives an advantage over other competitors to its affiliate. In cases where utility affiliated wholesale generators (UWG) are selling power to their parents, market power may be exercised if:

- utilities offer higher prices or more favorable contract terms for power to their affiliated UWG;
- the UWG has access to inside information regarding the terms and conditions of its parent's power supply solicitation;
- utilities exercise discretion with regard to dispatch decisions in favor of UWG affiliates; and
- utilities structure competitive bid evaluation criteria to favor affiliates.

2) **Cross-subsidies**: Cross-subsidy occurs when ratepayers' capital is used to reduce the cost of constructing or operating the UWG, while profits earned by the utility affiliate accrue to the shareholders and are not passed back through to benefit the ratepayer. In addition, competition is harmed if the affiliate gains a cost advantage from subsidized costs.

In cases where the costs associated with an UWG can be passed, directly or indirectly, through to the parent's ratepayers, abuse of market power may occur if:

- utilities pass the construction, operation, siting, insurance or other costs associated with UWGs onto regulated activities to shift the risk associated with investing in UWGs from shareholders to their ratepayers;
- utilities provide engineering, legal and other expert assistance that was funded by ratepayers to unregulated UWGs; and,
- utility ratepayers finance construction of a project and the project is subsequently transferred to an affiliate at book value.

3) **Abuse of control over essential transmission facilities**: Competitive markets in electric generation cannot develop unless suppliers can move their product to market over utility-owned transmission lines. The recent report by the FERC Transmission Task Force concluded that, "The current market power of transmission incumbent is so pervasive that independent power producers are unlikely to be willing to take substantial financial risks in the absence of assured access to the grid at reasonable prices." Utilities control access to those transmission lines and that control may be used to exercise market power if:

- utilities make transmission access available to affiliates while denying access to competitors;
- utilities deny transmission access to favor competing proposed rate-based plants;
- utilities refuse to make transmission capacity or availability information public;
- utilities decline to sign letters of intent to provide wheeling service to independents or cause delay which prevents independents from meeting bidding deadlines or other bidding requirements; and,
- utilities make access available to all, but impose prices, terms or conditions on transmission service for non-affiliated entities that make projects unfeasible or uneconomic.

Clearly, Congress needs to address market power issues in the context of PUHCA reform and identify the appropriate mechanisms to include in the legislation to ensure that the benefits of true competition will be realized.

III. ELEMENTS OF PUHCA LEGISLATION NECESSARY TO ACHIEVE COMPETITION IN BULK POWER MARKETS.

Any amendment to the Public Utility Holding Company Act must include protections against anti-competitive abuses by facilities exempted from PUHCA which are owned by parties who potentially possess market power. NIEP believes that protections under other existing regulation, such as the Federal Power Act, are not adequate nor can they be used in a timely manner to truly ensure fair competition in power markets. A good regulatory system to ensure fair competition must have clear rules and penalties. By contrast, the current regulatory structure is ambiguous and uncertain with limited remedies.

Therefore, NIEP proposes that the following additional elements must be incorporated into S.406 to reach the goals of enhancing competition in power generation markets and maintaining consumer protections.

A. PROTECTIONS AGAINST ABUSE OF MARKET POWER

1) Legislative Language Endorsing Fair Competition.

Congress should strongly endorse the need for fair competition in the electric generation market. There is no explicit reference in PURPA or the Federal Power Act to the desirability of competition in bulk power markets. Congress should also explicitly recognize FERC as having primary responsibility to prevent abuse of market power in wholesale markets and require FERC to exercise its authority through state regulators whenever practical.

2) Stronger Remedies for Anti-competitive Activities

Congress should mandate that FERC use its authority under Sections 205 and 206 of the Federal Power Act (FPA) to determine that exempt wholesale generators (EWGs) seeking approval for wholesale rates as "just and reasonable" have not abused market power.

The House of Representatives version of the "Competitive Wholesale Generation Act of 1989" (HR 3692) incorporated similar language on transmission, requiring that FERC not accept any rates as "just and reasonable" if a utility uses its market power to advantage an affiliate UWG.

The major shortcoming of FERC's ability to protect against market power abuse under Sections 205 and 206 of the FPA is in the inadequate relief it can offer injured competitors. FERC can refuse to approve an offender's proposed rate, but this is cold comfort to a competitor which has lost out in the bidding month or years earlier. In addition to rate disapproval, the FERC should be empowered to impose penalties on abusers of market power who cause damage, including the award of treble damages to injured competitors, divestiture, and rescission of the PUHCA exemption.

3) Restrictions on Utility Wholesale Generation

PUHCA was intended to protect consumers and investors against the abuse of market power thought cross-subsidies, self-dealing and control of essential facilities. PUHCA's restrictions are not appropriate for entities which lack market power. Wholesale generators which are not affiliated with utilities by definition lack market power and thus should be exempted from PUHCA without further restriction. By contrast, utilities because of their single buyer and seller status and their control over essential facilities have market power. Utility affiliated wholesale generators cannot be presumed to lack market power because of their relationship with their parent.

Two Classes of Exempt Generators

S. 406, "the Competitive Wholesale Generation Act of 1989" creates a category of generators exempt from PUHCA called "exempt wholesale generators" or "EWGs". We believe that two categories of EWGs should be established to distinguished between "independent wholesale generators" (IWGs) and "utility affiliated wholesale generators" (UWGs). This distinction would recognize the inherent difference in market power between these two classes of EWGs.

An IWG is defined as an EWG which has no ownership interest by a utility.

Ownership Limitation

A UWG is defined as an EWG which has any ownership interest held by a utility. A utility interest in a UWG would be limited to less than fifty percent of the equity or rights to revenues and profits generated by the facility. This limitation would be reviewed by the Congress five years after the date of enactment of the PUHCA legislation and removed by act of Congress upon the recommendation by the Commission on Competition in Electric Power Markets (see Section C below).

In a truly competitive market with open access to transmission, there would be no need for ownership limitations. We believe that in the absence of meaningful reform of transmission policy, and in the presence of potential abuse of market power, the concept of an ownership limitation on utilities as a check on potential abuse of monopoly power, first embraced by Congress in the enactment of PURPA, should be applied to the utility ownership of EWGs. Indeed, the 50 percent ownership limitation under PURPA has not prevented vigorous participation by utilities, but has facilitated entry and participation by true independents into generation markets.

The ownership restriction would apply for a five-year transitional period until the Commission on Competition can assess and report to Congress on the impact of PUHCA reform of transmission policies and ownership limitations on competitive markets.

In addition, limitations on utility ownership of UWGs could prevent consolidation in the generation industry to the extent it has been seen in airlines since deregulation. Congress and the public have become increasingly concerned with the harmful effects on competition of concentration of airlines. If utility ownership of a UWG is restricted initially, excessive concentration may be avoided without additional future legislation.

Restriction on Affiliate Sales

A UWG would not be permitted to sell power to any affiliated utility or any other utility in the same centrally dispatched power pool as the affiliate. This prohibition would apply whether the UWG is located inside or outside the service territory or centrally dispatched power pool of the affiliate. It would also apply to joint ventures between UWGs and unrelated suppliers and to UWG and subsidiaries of centrally dispatched multistate holding companies.

This rule would reduce incentives for self-dealing, cross-subsidies and daisy-chaining and help maintain confidence in the fairness of the competition.

Conversion of Rate-based Facilities

We support the proposal that rate-based facilities may be converted to EWGs if approved by state public service commissions. Such conversions should be permitted only if the entire facility is converted. The risks of cross-subsidy in a hybrid plant which is partially an EWG and partially a rate-based plant could not be controlled. The FERC recognized this problem in its proposed IPP rule when it defined IPPs as "facilities not in a utility's wholesale or retail rate base and not otherwise afforded the assurances of cost recovery." (See Regulations Governing Independent Power Producers, RM88-4-000, at p.35 (March 16, 1988)

Organization of UWGs as Separate Subsidiaries

A UWG must be organized as a separate subsidiary of the associated utility, not organized as a division within the utility itself. This separation is necessary to assist state regulators in their monitoring of cross-subsidies and self-dealing by the associated utility. The books and records of UWGs should be available to state regulators to discharge their regulatory duties and distinguish between the costs of a UWG subsidiary and its utility parent.

4) **Prevention of Cross-Subsidy**

Currently, under PUHCA, the Securities and Exchange Commission (SEC) has regulations defining and restricting cross-subsidy among subsidiaries of registered holding companies. FERC should be directed to promulgate regulations which define cross-subsidy for exempt utility holding companies which own UWGs and delegate efforts to prevent such cross-subsidies to the states wherever practical. UWGs should not be allowed to gain a financing advantage by relying on guarantees from their utility parents. Utilities should be allowed to invest retained earnings in a UWG, but provide no other financial support.

Similar protections against market power abuse have been proposed or can be found in legislation or legal decisions promoting competition in other industries, such as telephones and airlines. Protections against these abuses were incorporated into the court mandated telephone settlement or in pending telecommunications legislation introduced in the House by Representatives Swift (D-WA) and Tauke (R-IA) and have been recently proposed for the airline industry in legislation introduced in the Senate by Senators McCain (R-AZ) and Danforth (R-MO). For example:

Self-dealing: In the airline industry, joint-marketing relationships, including code-sharing by hub and regional flights, between major airlines and regional or feeder lines flying into hubs are increasingly viewed as self-dealing. Recent Senate legislation proposes banning code-sharing to remove the marketing advantage between major airlines and regional affiliates.

In addition, control of computerized reservation systems (CRS) gives airline owners of these systems an advantage over non-owning airlines. Competitors are disadvantaged in access to potential passengers and through operation of the CRS, charged higher rates for access to the CRS. The proposed legislation would require nondiscriminatory access to CRS and prohibit airlines from owning, operating or controlling CRS.

On the telephone side, local companies were not permitted to enter equipment manufacturing for fear they would favor their own affiliated equipment suppliers through their control over the timing and specification of equipment acquisition. Recent legislation proposed by Representatives Swift (D-WA) and Tauke (R-IA) would allow local companies to enter the equipment supply business, subject to a requirement for non-discrimination by the local company in the acquisition of equipment.

Cross-subsidies: The courts allowed local telephone companies to diversify into non-telephone businesses. However, in a recent review of the divestiture, the judge has alleged a clear pattern of cross-subsidy in the diversified activities. In addition, a recent Federal Communications Commission audit found that NYNEX (one of the seven "Baby Bells") regulated businesses had subsidized more profitable non-regulated businesses by amounts exceeding $120 million.[9] Furthermore, a number of regulatory commissions have alleged cross-subsidies in the form of misallocation of management time, training for competitive businesses at ratepayer expense and "cherry-picking" of personnel. To protect ratepayers, the Swift-Tauke bill would require unregulated subsidiaries to be financially isolated from the monopoly core business.

5. Transmission Access

For ratepayers to receive the full benefit of a competitive market in generation, wholesale suppliers need predictable access to and pricing of the use of transmission facilities controlled by utilities. At a minimum, a utility should not be able to use its control of transmission facilities to gain an advantage for itself or any other party or to cause injury to another party in a competitive procurement or contract negotiation for supply of power to a utility. FERC should be granted explicit authority to promulgate and enforce rules to prevent the use of transmission capacity by a utility to gain a competitive advantage in electricity generation markets. In exercising this authority, FERC should place the burden of proof on the owner of the transmission facility, not the party alleging injury.

With respect to the larger issues of open access to transmission facilities for wholesale suppliers, we recognize the complex political, technical, and economic nature of this issues. At this time, we do not advocate open access to transmission outside of specific competitive situations. We also recognize there is wide disagreement of whether the timing is right to deal with this issues in the context of PUHCA amendment, but we believe that PUHCA reform must go forward with safeguards against the abuse of transmission control by utilities for anti-competitive purposes.

Similar issues regarding the control of essential facilities were again addressed in the telephone and airline industry cases.

Control over essential facilities: Since airline deregulation, a few airlines have come to dominate key airports, known as fortress hubs. These airlines account for high percentage of passengers and flights, own or control gate space and on-ground facilities and dominate access to gates and passengers. Many consider the hubs and their corresponding networks to be impenetrable to competing airlines. The Senate bill currently being considered proposes that concentration and dominance of fortress hubs should be presumed to be unfair and thus, makes injunctive relief available to competitors. It also would allow airports to raise funds to expand capacity to enhance competition.

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[9] Wall Street Journal, **Wrong Numbers: NYNEX Overcharged Phone Units for Years, An FCC Audit Finds**, January 9, 1990, page A1.

The structure of the telephone settlement was premised upon the monopoly characteristics of the local exchange and the competitive nature of other industry segments. The local switch, which provides access to the ultimate customer, was deemed a bottleneck essential facility to which equal access was to be provided for long distance competitors and, later, for information service providers. In addition, because of their monopoly power over the local switch, the local companies were precluded from entering the information service industry or equipment manufacturing. The Swift-Tauke proposal to allow greater local company activity in those businesses would maintain the requirement for nondiscriminatory access and require a finding of competition by the Federal Communications Commission.

Clearly, similar market power concerns appear consistently in each industry examined. Furthermore, in each case, the level of structural and regulatory protections required or called for in legislative proposals is consistent with or exceeds NIEP's recommendations for market power protections in a PUHCA amendment.

B. STATE REGULATION OF EWGs

Congress should explicitly affirm the power of state regulatory commissions to disallow costs imprudently incurred by jurisdictional utilities in purchases from EWGs (application of the Pike County doctrine). States should be required to exercise this authority through prudency review at the time of purchase.

Most states have utility statutes which are designed to regulate the corporate and financial structure of traditional utilities which have distribution franchises, with the ability to raise revenue through their rate structure and to pass through the costs to consumers. Although in many states EWGs may be classified as utilities and therefore subject to the jurisdiction of these statutes, these regulations are not appropriate for entities such as EWGs and QFs which do not have the pass-through capability. This type of exemption from state regulation was provided for QFs under PURPA and should be provided for EWGs. The organization and financial burdens which these laws impose would put EWGs at a competitive disadvantage.

EWGs should therefore be exempt from the state corporate and financial regulations applied to utilities. EWGs would continue to be subject to state siting and environmental controls.

C. COMMISSION ON COMPETITION IN ELECTRIC POWER MARKETS

Congress should establish a Commission on Competition in Electric Power Markets to review the status of competition in electric generation markets and make specific findings on:

1) the relationship between access to and control of transmission facilities (including the feasibility of retail wheeling and the roles of Federal, state or regional authorities in removing bottlenecks and allocating capacity shortages) and competition; and

2) the relationship between the 50 percent utility ownership limitation of EWGs and competition.

The membership of the Commission should represent all sectors of the electric power industry as well as consumer interests. The Commission should report its findings to the Congress five years after the date of enactment of legislation modifying PUHCA.

IV. CONCLUSION

The National Independent Energy Producers support amendment to the Public Utility Holding Company Act so long as it truly increases competition in power markets. PUHCA has protected electricity consumers from the unfettered abuse of market power for over fifty years. However, changes have taken place in the electric generating business that could not have been contemplated by PUHCA's drafters. Advances in technology, changing economics, and new regulatory schemes spurred competition to supply electric generation.

Allowing competition to be the dominant structure in supplying the new capacity needed by this nation benefits ratepayers. However, it requires removing the statutory barriers to entry under PUHCA while maintaining PUHCA's strong consumer protections. NIEP supports amendment to PUHCA to allow generators to enter the market to compete to supply generation. However, NIEP believes that fair competition will only result if the PUHCA amendment contains the market power protections enumerated in this testimony.

ELCON

Statement of the
Electricity Consumers Resource Council (ELCON)
on Proposed Changes to the
Public Utility Holding Company Act of 1935 (PUHCA)
presented to the
Committee on Energy and Natural Resources
United States Senate
December 4, 1989

I. INTRODUCTION

The Electricity Consumers Resource Council (ELCON) is pleased to offer the following comments regarding the "Competitive Wholesale Electric Generation Act of 1989."[1] This proposed legislation would amend the Public Utility Holding Company Act of 1935 (PUHCA or the Act).

ELCON is a consumer group -- an association of large industrial consumers of electricity. Our members have facilities in most of the 50 states and many foreign countries. They produce a wide range of products including steel, chemicals, petroleum, industrial gases, glass, motor vehicles, electronics, appliances, textiles and food. Our 20 companies consume more than four percent of all of the electricity in the United States. A Fact Sheet describing our purpose and fundamental principles is attached.

Many of the ELCON member companies generate and cogenerate large quantities of power. Notwithstanding this fact, we emphasize that ELCON is a consumer group. Our members buy far more electricity than they produce.

Our members need an adequate and reliable electricity supply. However, they must be able to purchase it. Thus, they have a deep and continuing interest in electricity issues which have the potential to significantly impact either the price or reliability of the electricity supply. Amendments to PUHCA can affect both the structure of the industry and the effectiveness of regulators. Therefore, we have a great interest in this issue.

II. BACKGROUND

Our society regulates public utilities because traditionally they have been shown to be natural monopolies providing essential services. As such, the opportunities and temptations are great for preferential dealings with utility-owned affiliates.

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[1] Amendment No. 267 to S. 406, Congressional Record, July 13, 1989, page S. 7943.

Utility abuse of market power led to the passage of PUHCA in the early days of regulation. Examples of such abuse included inadequate disclosures, imposition of affiliate costs on utility operations and obstruction of state regulation.

PUHCA significantly impacted the electric utility industry. Registered holding companies were tightly controlled by the Securities and Exchange Commission (SEC). PUHCA required that the SEC determine that acquisitions and diversifications are not detrimental to the public interest nor the interest of investors or consumers, and will serve the public interest by tending towards the economical and efficient development of an integrated public utility system. PUHCA requires registered companies to limit their operations to a single, integrated system. This means that registered holding companies cannot own non-integrated generators outside their system.

PUHCA allows the SEC to grant exemptions from the Act for holding companies meeting certain criteria. Presently there are nearly 200 exempt holding companies. Many have established subsidiaries that are actively developing -- or have developed -- independent power generators.

III. PROPOSED LEGISLATION

Some analysts assert that PUHCA is a substantial barrier to increased competition. These analysts argue that technological development in small scale generators have changed the nature of electric utilities so significantly that competition now can exist, at least between generators. They argue that PUHCA should be amended to remove barriers to new competitors. They assert that increased competition will benefit consumers.

In response, Senator Bennett Johnston (Chairman, Committee on Energy and Natural Resources, U.S. Senate) introduced the "Competitive Wholesale Electric Generation Act of 1989" (the "bill" or the "proposed legislation"). The bill would allow utilities, registered holding companies, exempt holding companies, construction contractors, equipment suppliers, industrials, etc., to create or acquire any number of exempt wholesale generators (EWGs) essentially free from PUHCA review.

IV. DISCUSSION

Industrial companies, including ELCON members, operate in increasingly competitive markets. They know the power of competition. They know that competition drives prices to the lowest level possible. They know that competition drives out inefficiencies. True competition will allow neither the existence of unnecessary cost nor preferential treatment for certain customers.

We believe that competition is coming -- at least to the generation side of the industry. We look favorably on the increased competition.

However, we look with caution. Consumers will benefit only if there are gains in real competition. Increases in the number of corporate owners of generators alone may not increase the level of competition -- especially if the "new" entrants are utility affiliates that are not kept at "arms length" and utilities are able to block access by other competitors to distant markets.

With these thoughts and concerns clearly in mind, we carefully analyzed the assertions by advocates for change and formulated our position on PUHCA reform. The details of that position are attached. In summary:

A. The Need for Reform Has Not Been Demonstrated.

Capacity adequate to meet projected future needs is already planned. Specifically, the North American Electric Reliability Council (NERC) calculates that utility forecasts and construction plans show adequate reserve margins in 1998. The lights will not go out without PUHCA reform.

Additionally, both the willingness and ability to construct generators clearly has been demonstrated. Utilities have plans to build rate-base generators. Bidding programs are tremendously oversubscribed. "Independent power generators" such as the Ocean State project are proceeding, albeit slowly. Utilities and their affiliates clearly are part of this process. Indeed, utility affiliates were involved in over 11,000 MW of independent generating projects in 1988. This was nearly triple the 1987 level.

We have not seen evidence that this robust independent power development will soon cease. Indeed, Westinghouse Electric Corporation recently projected a sizeable increase in orders for power plants -- most from independent power producers. Westinghouse believes the increased orders will "ride a wave of demand stretching over the next six years."

B. For these reasons, we do not advocate legislative changes to PUHCA at this time. However, if changes are made, we believe that they should include certain key elements. Specifically:

1. State regulatory authority must be strengthened. They must have the ability to both disapprove pass through of imprudent power purchases and order the implementation of bidding programs.

2. A clear distinction should be made between "true independents" (IPPs) and "utility affiliates" (APPs).

3. IPPs should be encouraged when accompanied by adequate regulatory oversight of contract. IPPs should be exempt from PUHCA's integration requirements. They should make an initial filing, but not be subjected to a preacquisition review.

4. Utility ownership of APPs greatly increases the probability of utility self-dealing. A utility's zone of economic influence extends beyond its service territory. The potential for self-dealing declines the further the transaction is located from the parent.

   ELCON links PUHCA reform to transmission access through a "sliding scale" which recognizes the potential for self-dealing. The specifics of that sliding scale are set forth in Section II.D. of our position (copy attached). In essence, the degree of required transmission access decreases the further the affiliate is from the parent.

5. Construction contractors, equipment suppliers and "hybrids" (jointly-owned projects such as utility/IPPs, equipment supplier/utility, Wall Street/utility, etc.) do not automatically qualify as IPPs. However, such entities may be treated as IPPs if a preacquisition review demonstrates no financial, contractual or other relationships that would foster self-dealing.

C. The proposed legislation raises several significant concerns.

First, enactment of the bill would make state regulation more difficult and uncertain. The existing state authority over prudence is questionable. Recent Supreme Court decisions explicitly denied states the ability to conduct reviews when the utility regulated is a member of a holding company. The proposed legislation would increase the present uncertainty.

Further, relaxation of the integration requirements would make state regulation more difficult. States do not have jurisdiction over operations in other states. Yet, transactions with distant affiliates could involve preferential deals that could harm the customers of the utility.

The legislation also is woefully inadequate regarding the potential for self-dealing. Numerous opportunities exist that could entice a utility to offer sweetheart deals to their affiliates and/or discriminate against IPPs. Preferential treatment for affiliates are of several types. For example, utilities could:

1. Give competitive advantage to their APPs at the expense of the utility's customers (as Southern California Edison did for Mission Energy and other partially owned QFs);

2. Overpay for goods and services provided by affiliates (as Texas-New Mexico Power did for Capitol Cogeneration and both Florida Power and Utah Power & Light did in buying coal from subsidiaries);

3. Undercharging for goods and services provided to affiliates (as Central Maine, SCE, FPC and Sierra Pacific did with their affiliates); and

4. Transfer utility assets to affiliates at depreciated --rather than market -- prices (as Tucson Electric did with Alamito).

Some argue that the fear of self-dealing is over-blown. The bill would do no more than allow prospective developers, whether they were utilities or non-utilities, to use the holding company structure to develop IPPs. Prices would still be controlled by FERC. FERC has made it absolutely clear that price flexibility is dependent upon the absence of market power.

We are not convinced. It is no answer to the self-dealing risks potentially posed by utility IPPs to say that FERC may, in adjudicatory proceedings, require IPPs to demonstrate that they lack market power to obtain variances from cost-based pricing. Ad hoc adjudication gives no assurance to ratepayers or true IPPs that self-dealing and monopoly abuse will not occur from utility-affiliated APPs. Statues have some permanence; ad hoc precedents do not. FERC declined to finalize its proposed rule for IPPs precisely because a consensus does not exist as to what the ground rules should be for market-based pricing by IPPs including utility-affiliated APPs. PUHCA legislation presents the opportunity to address these concerns in an integrated fashion.

Moreover, FERC's current statutory authority over transmission is so limited that its ability to avoid the unfair advantage that utility-affiliates enjoy over true IPPs is highly uncertain.

V. CONCLUSION

For the reasons set forth above, ELCON opposes the proposed legislation.

ELCON POSITION ON PUHCA REFORM

ELCON

I. **The need for reform of the Public Utility Holding Company Act of 1935 (PUHCA) has not been demonstrated:**

  A. Bidding programs are tremendously oversubscribed.

  B. Non-utility generators are being built.

  C. We have not seen evidence that PUHCA restricts the construction of more efficient generators.

II. **We do not advocate legislative changes to PUHCA at this time. However, if changes are made, they should include the following elements.**

  A. State regulatory authority must be strengthened.

    1. States must have adequate authority to regulate.

    2. States should have the authority to disapprove pass through of imprudent power purchases. This is known as the Pike County doctrine. The Pike County doctrine stands for the proposition that, while states may not regulate rates charged for a wholesale sale, the state regulatory agency may review the decision of the utility to make a particular wholesale purchase. In both Mississippi and Nantahala, the Supreme Court denied states the ability to conduct a Pike County review when the utility regulated is a member of a holding company system.

    3. States must have access to all books and records of utility affiliates necessary to carry out their required functions.

    4. States should have the authority to order the implementation of bidding programs.

  B. A clean distinction should be made between "true independents" (IPPs) and "utility affiliates" (APPs).

    1. IPPs are entities that generate electricity for sale and are not affiliated with a utility.

    2. APPs are entities with stock ownership, contractual relationships, or other financial relations that would foster self-dealing between the APP and the purchasing utility or utility holding company.

  C. True independents (IPPs) should be encouraged when accompanied by adequate regulatory oversight of contract:

    1. Oversight can take the form of contract review and/or a fair and nondiscriminatory bidding system for power procurement.

    2. IPPs:
      a. Should be exempt from Sec. 10 (c) (2) of PUHCA requiring integration of all facilities.
      b. Must make an initial filing, similar to that required by QFs. However, a preacquisition review would not apply.
      c. Should not be required to file annual reports.

D. Potential self-dealing must be mitigated:

Utility ownership of APPs can greatly increase the probability of utility self-dealing. A utility's zone of economic influence extends beyond its service territory. It extends throughout a holding company and an interconnected power pool. However, the potential for self-dealing declines the further the transaction is located from the parent.

ELCON advocates transmission access as a requisite to obtaining the economic efficiencies which these reforms are intended to achieve. An efficient market will satisfactorily address the temptation to self-deal.

ELCON links PUHCA reform to transmission access through a "sliding scale" which recognizes the potential for self-dealing. Specifically:

1. Existing law allows utilities to maintain an exemption to PUHCA while owning up to 10% of an affiliated power producer (APP). Utilities may own more than allowed by current law and maintain their exemption after:
    a. A preacquisition review,
    b. Approval is received from affected state PUCs, and
    c. Assurance of compliance with the transmission requirements specified below
2. Electricity sales from APPs located outside the utility's interconnected power pool or holding company should be conditioned on that utility agreeing to supplier wheeling. Supplier wheeling involves the movement of power from non-utility generators to a distant utility.
3. Electricity sales from APPs to other members of the interconnected power pool should be conditioned on:
    a. the existence of a fair and nondiscriminatory bidding process for utility power procurement and
    b. the availability of a limited form of transmission access. Specifically
        (1) Applicants that meet specified characteristics should be allowed to apply for wheeling orders.
        (2) The appropriate regulatory commission should hold a summary proceeding prior to issuing a wheeling order.
        (3) State commissions should have authority over intrastate transactions.
        (4) FERC should have authority both to order and to set rates for interstate wheeling
        (5) Rules should establish a rebuttable presumption that the capacity to wheel exists.
        (6) Commissions should have the authority to order the construction of both new and modifications to existing facilities if the net costs attributable to an applicant are borne by that applicant and there is no significant adverse impact on the system
        (7) Upon request, utilities should be required to establish both wheeling tariffs and terms and conditions on a nondiscriminatory basis.
        (8) Wheeling rates should be based on cost-of-service.
        (9) Commissions should have the authority and the responsibility to resolve disputes expeditiously and order interim wheeling.
        (10) Wheeling customers who desire to reestablish firm service should be viewed as a new customers by the utility with no superior or inferior standing unless other arrangements (e.g., standby rates, contracts, etc.) have been negotiated.

[NOTE: The wheeling policy outlined in the ten points above is described in more detail in the publication titled ELCON's Wheeling Policy, available upon request.]

4. Electricity sales from APPs to the utility owning the APP should be conditioned on:
    - a. the availability of nondiscriminatory, open transmission access (contract carriage),
    - b. adequate regulatory oversight and
    - c. the existence of a fair and nondiscriminatory bidding process for utility power procurement.

5. Any changes to PUHCA should not affect the regulatory treatment of existing, utility-owned, non-ratebased generation. Additionally, PUCs should be able to waive the transmission requirements contained in 2 and 3 above for generators that will be non-ratebased for a specific period of time, but then will be brought into ratebase.

6. Construction contractors, equipment suppliers and "hybrids" (jointly-owned projects such as utility/IPPs, equipment supplier/utility, Wall Street/utility, etc.) do not automatically qualify as "true independents."
    - a. Entities may be treated as "true independents" after a preacquisition review and demonstration of no stock ownership interest, contractual relationship, or other financial relationships that would foster self-dealing between the contractor and the purchasing utility or utility holding company.
    - b. Entities should be treated as "utilities" if financial relationships are shown to be greater than *de minimus*.

E. Utility ownership -- Utility ownership of APPs should be limited to 50% until it is determined that federal and state regulators have developed sufficient expertise to prevent anti-competitive behavior by affiliates. Additionally, no utility should be allowed to own more than 50% or demonstrated control of an APP, whichever is lower, unless transmission is required such as that outlined in II. D. above.